

---

---

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

---

**Form 10-K**

(Mark One)

**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 1-33825**

---

**El Paso Pipeline Partners, L.P.**

*(Exact Name of Registrant as Specified in Its Charter)*

**Delaware**

*(State or Other Jurisdiction of  
Incorporation or Organization)*

**26-0789784**

*(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 Representing Limited Partner Interests

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. Yes  No .

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  No .

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer  Accelerated filer   
Non-accelerated filer  (Do not check if a smaller reporting company) Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes  No .

The aggregate market value of the common units representing limited partner interests held by non-affiliates of the registrant was approximately \$3,957,106,000 on June 29, 2012, the last business day of the registrant's most recently completed second fiscal quarter, based on the price of \$33.80 per unit, the closing price of the common units as reported on the New York Stock Exchange on such date.

There were 215,789,325 Common Units and 4,403,765 General Partner Units outstanding as of January 31, 2013.

**Documents Incorporated by Reference: None.**

---

---

**EL PASO PIPELINE PARTNERS, L.P.**  
**TABLE OF CONTENTS**

	<u>Caption</u>	<u>Page Number</u>
	<u>PART I</u>	
Items 1 and 2.	<a href="#">Business and Properties</a>	<a href="#">1</a>
Item 1A.	<a href="#">Risk Factors</a>	<a href="#">9</a>
Item 1B.	<a href="#">Unresolved Staff Comments</a>	<a href="#">26</a>
Item 3.	<a href="#">Legal Proceedings</a>	<a href="#">26</a>
Item 4.	<a href="#">Mine Safety Disclosures</a>	<a href="#">26</a>
	<u>PART II</u>	
Item 5.	<a href="#">Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities</a>	<a href="#">27</a>
Item 6.	<a href="#">Selected Financial Data</a>	<a href="#">28</a>
Item 7.	<a href="#">Management’s Discussion and Analysis of Financial Condition and Results of Operations</a>	<a href="#">29</a>
Item 7A.	<a href="#">Quantitative and Qualitative Disclosures About Market Risk</a>	<a href="#">44</a>
Item 8.	<a href="#">Financial Statements and Supplementary Data</a>	<a href="#">64</a>
Item 9.	<a href="#">Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</a>	<a href="#">45</a>
Item 9A.	<a href="#">Controls and Procedures</a>	<a href="#">45</a>
Item 9B.	<a href="#">Other Information</a>	<a href="#">45</a>
	<u>PART III</u>	
Item 10.	<a href="#">Directors, Executive Officers and Corporate Governance</a>	<a href="#">46</a>
Item 11.	<a href="#">Executive Compensation</a>	<a href="#">50</a>
Item 12.	<a href="#">Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters</a>	<a href="#">53</a>
Item 13.	<a href="#">Certain Relationships and Related Transactions and Director Independence</a>	<a href="#">56</a>
Item 14.	<a href="#">Principal Accounting Fees and Services</a>	<a href="#">57</a>
	<u>PART IV</u>	
Item 15.	<a href="#">Exhibits and Financial Statement Schedules</a>	<a href="#">59</a>
	<a href="#">Index to Financial Statements</a>	<a href="#">64</a>
	<a href="#">Signatures</a>	<a href="#">103</a>

Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	LNG	= liquefied natural gas
BBtu	= billion British thermal units	MDth	= thousand dekatherm
Bcf	= billion cubic feet	MMcf/d	= million cubic feet per day
Dth	= dekatherm	FERC	= Federal Energy Regulatory Commission
NGL	= natural gas liquid	GAAP	= Generally Accepted Accounting Principles in the United States

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

## PART I

### Item 1 and 2. *Business and Properties.*

#### *Overview*

We are a Delaware master limited partnership (MLP) formed in 2007 to own and operate interstate natural gas transportation and terminaling facilities. When we refer to "EPB," "us," "we" or "our" we are describing El Paso Pipeline Partners, L.P. and/or our subsidiaries. Our common units, which represent limited partner interests in us, trade on the New York Stock Exchange under the symbol "EPB." We are controlled by our general partner, El Paso Pipeline GP Company, L.L.C., a wholly owned subsidiary of El Paso LLC (formerly El Paso Corporation) (El Paso). Kinder Morgan, Inc.'s (KMI) acquisition of El Paso became effective on May 25, 2012. El Paso is a wholly owned subsidiary of KMI.

As of December 31, 2012, we own Wyoming Interstate Company, L.L.C. (WIC), Southern LNG Company, L.L.C. (SLNG), Elba Express Company, L.L.C. (Elba Express), Southern Natural Gas Company, L.L.C. (SNG), Colorado Interstate Gas Company, L.L.C. (CIG) and Cheyenne Plains Investment Company, L.L.C. (CPI), which owns Cheyenne Plains Gas Pipeline Company, L.L.C. (CPG). In May 2012, we acquired the remaining 14% interest in CIG and a 100% interest in CPI from El Paso. For additional information related to these acquisitions, see Note 3 to our consolidated financial statements included elsewhere within this report.

WIC and CIG are interstate pipeline systems serving the Rocky Mountain region. CPG has an interstate pipeline which serves the Rocky Mountain and Midwest regions. SLNG owns the Elba Island LNG storage and regasification terminal near Savannah, Georgia. Elba Express is an interstate pipeline system serving the southeastern region of the United States. SNG is an interstate pipeline system which originates in the producing Gulf Coast region of the United States and serves demand in the Southeastern region of the United States.

Our pipeline systems, storage facilities and LNG receiving terminal operate under tariffs approved by the FERC that establish rates, cost recovery mechanisms and other terms and conditions of services to our customers. The fees or rates established under our tariff are a function of our cost of providing services to our customers, including a reasonable return on our invested capital.

#### *Financial Information*

See Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 15 "Exhibits and Financial Statement Schedules" for financial information related to our operating results and financial condition. For financial information related to significant customers, see Note 13 to our consolidated financial statements included elsewhere in this report.

#### *Outlook for 2013*

We expect to declare cash distributions of \$2.55 per unit for 2013, a 13% increase over our 2012 distributions of \$2.25 per unit. Our 2013 budget includes the expected acquisition of 50% of Gulf LNG Energy LLC from KMI. Our growth is expected to be driven by our stable, regulated natural gas pipeline and storage assets, LNG business and incremental cost and growth synergies related to KMI's purchase of El Paso. In 2013, we expect to generate earnings before depreciation and amortization (EBDA) of \$1.22 billion (adding back our share of joint venture depreciation and amortization). We expect to produce excess cash flow of more than \$25 million above the 2013 distribution target of \$2.55 per unit.

#### *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," 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 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.

***Our Assets***

The table below and discussion that follows provides detail of our pipeline systems as of December 31, 2012:

Transmission System	As of December 31, 2012					Average Throughput		
	Ownership Interest	Miles of Pipeline	Design Capacity	Storage Capacity	Remaining Weighted Average Contract Life	2012	2011	2010
	(%)		(MMcf/d)	(Bcf)		(Years)	(BBtu/d)	
SNG <sup>(1)</sup>	100	7,200	3,892	60	6	2,684	2,463	2,505
CIG <sup>(2)(3)</sup>	100	4,300	4,611	37	7	2,159	2,128	2,131
WIC <sup>(4)</sup>	100	800	3,740	—	5	2,884	2,482	2,561
CPG	100	400	1,105	—	5	380	495	751
Elba Express <sup>(5)</sup>	100	200	1,000	—	27	—	—	—

- (1) SNG's storage capacity includes 29 Bcf of storage capacity associated with its 50% ownership interest in Bear Creek Storage Company, LLC (Bear Creek), a joint venture with Tennessee Gas Pipeline Company, L.L.C. (TGP), our affiliate.
- (2) Volumes reflected are 100% of the volumes transported on the CIG system.
- (3) CIG's storage capacity includes 7 Bcf of storage capacity from the Totem Gas Storage facility (Totem), which is owned by WYCO Development LLC (WYCO), CIG's 50% equity investee.
- (4) WIC's throughput includes 221 BBtu/d, 179 BBtu/d and 183 BBtu/d transported by WIC on behalf of CIG and 22 BBtu/d, 25 BBtu/d and 71 BBtu/d transported by WIC on behalf of CPG for the years ended December 31, 2012, 2011 and 2010, respectively.
- (5) Elba Express was placed in service in March 2010 and although capacity is under contract, the average volumes transported during 2012, 2011 and 2010 were not material.

*SNG*

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

*CIG*

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

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

#### *WIC*

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

#### *CPG*

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

#### *Elba Express*

Elba Express owns the Elba Express pipeline which transports natural gas supplies from the Elba Island LNG terminal to markets in the southeastern and eastern United States. Under a firm transportation service agreement, the entire capacity of Elba Express is contracted to Shell NA LNG LLC (Shell LNG) for 30 years at a fixed rate that will be reduced beginning on December 31, 2013 and remains flat thereafter with respect to current facilities. The firm transportation service agreement is supported by a parent guarantee from Shell Oil Company (Shell) that secures the timely performance of the obligations of the agreement.

#### *SLNG*

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

### ***Markets and Competition***

Our customers consist of natural gas distribution and industrial companies, electric generation companies, natural gas producers, other natural gas pipelines and natural gas marketing and trading companies. We provide transportation and storage services in both our natural gas supply and market areas, and in doing so, we compete with other pipeline service providers as well as alternative energy sources such as coal, nuclear energy, wind, hydroelectric power, solar and fuel oil.

The natural gas industry has experienced a major shift in supply sources, from conventional to unconventional, such as from shale formations. This is primarily due to the success in horizontal drilling and hydraulic fracturing techniques, which has led to an overall increase in production of natural gas. Further, high demand for domestic oil production has resulted in an increase in the production of associated gas, or natural gas found in association with oil. These new supply sources will affect the supply patterns, the flows and the rates that can be charged on pipeline systems. The impacts will vary among pipelines according to the location and the number of competitors attached to these new supply sources. Our SNG system is directly connected to the Haynesville Shale formation in northern Louisiana and indirectly connected, through new interconnecting pipelines, to the Barnett Shale, Bossier Sands, Woodford Shale and Fayetteville Shale. Moreover, our gas pipelines serving the Rocky Mountain area are directly connected to the Niobrara Shale formation along the Front Range of the Rockies in Colorado and Wyoming.

Another change in the supply patterns is the reduction of imports from Canada and increased exports to Mexico. The decreases in imported supplies from Canada have been the result of declining conventional production and increasing demand in Canada as well as increased production from shale formations in the northeast United States. On the southern border, exports to Mexico are increasing and may increase further over time as demand growth exceeds production growth in that country. In addition to these trends in Canada and Mexico, imports of LNG to the United States have been declining over the last several years in response to increased United States shale gas production which has resulted in a decline in United States natural gas prices relative to gas prices in Europe and Asia. The projected gas price disparity between United States and European/Asian markets suggests that North America could change from a net importer of LNG to a net exporter of LNG before the end of this decade.

Electric power generation has been the source of most of the demand growth for natural gas over the last 10 years, and this trend is expected to continue. The growth of natural gas in this sector is influenced by competition with coal and economic growth. Short-term market shifts have been driven by relative electricity generation costs of coal-fired plants versus gas-fired plants. A long-term market shift in the use of coal in power generation could be driven by environmental regulations. The future demand for natural gas could be increased by regulations limiting or discouraging coal use. However, natural gas demand could potentially be adversely affected by laws mandating or encouraging renewable power sources. Industrial demand has also grown recently with the economic recovery and low natural gas price environment, and this sector offers an opportunity for continued growth. All of the aforementioned factors have led to increased demand for domestic supplies and related transportation services over the last several years.

For a further discussion of factors impacting our markets and competition, See Item 1A "Risk Factors."

#### *SNG*

The Southeastern market served by the SNG system is one of the fastest growing natural gas demand regions in the United States. Demand for deliveries from the SNG system is characterized by two peak delivery periods, the winter heating season and the summer cooling season. SNG competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative delivery points. Natural gas delivered from the SNG system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal, fuel oil and nuclear. Some of SNG's largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. In addition, SNG competes with third party pipelines and gathering systems for connection to new supply sources.

SNG's most direct competitor is Transco, which owns pipelines extending from Texas to New York. It has firm transportation contracts with SNG's largest customer, Atlanta Gas Light Company, a subsidiary of AGL Resources.

#### *CIG*

Our CIG system serves two major markets, an on-system market and an off-system market. The on-system market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Competitors in this market consist of an interstate pipeline, local production from the Denver-Julesburg basin and long haul shippers who elect to sell into this market rather than the off-system. The off-system market consists of the transportation of Rocky Mountain natural gas production from multiple supply basins to interconnections with other pipelines in the Midwest, Southwest, California and the Pacific Northwest. Competition for our off-system market consists of other interstate pipelines, including WIC, that are directly connected to our supply sources. CIG also faces competition from other existing pipelines and alternative energy sources that are used to generate electricity such as hydroelectric power, wind, solar, coal and fuel oil.

CIG also competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Some of CIG's largest customers could obtain a significant portion of their natural gas requirements through transportation from other pipelines.

#### *WIC*

Our WIC system competes with other interstate and intrastate pipelines for deliveries to multiple-connection customers. Its four largest customers generally have competitive transportation alternatives for significant portions of their natural gas transportation requirements. These competitor pipelines include the Rockies Express Pipeline LLC (Rockies Express), Bison Pipeline LLC (Bison) and CIG. Expiring contracts on the WIC Medicine Bow lateral were not renewed due to the decline in drilling in the Powder River Basin and the commissioning of Bison in early 2011. In addition, WIC competes with CIG, third party pipelines and gathering systems for connection to the supply sources in the United States Rocky Mountain region. Natural gas delivered from the WIC system competes with alternative energy sources used to generate electricity, such as hydroelectric power, solar, wind, coal and fuel oil.

#### *SLNG*

SLNG's terminal capacity is completely subscribed under long-term contracts with subsidiaries of BG and Shell. Revenue from these contracts is predominantly based on reservation charges; therefore, changes in throughput at the terminal driven by domestic or global competition will have relatively little effect on our revenue stream or profitability. Since SLNG's Elba Island LNG terminal is directly connected to three interstate pipelines, and indirectly connected to two others, it is readily accessible to markets in southeast United States, Florida and the mid-Atlantic as well as supply from the newly developed shale formations. The recent proliferation of gas production from shale formations has shifted the desire of global LNG suppliers from importing LNG to the United States to seeking opportunities to export LNG from the United States. SLNG is well positioned for the LNG export opportunity. See Item 7 "Liquefaction Project" for further discussion regarding LNG exports. Several other competing LNG export projects have recently been proposed. LNG export demand is highly dependent on domestic natural gas pricing relative to pricing in European and Asian markets. As such, the total LNG export market is difficult to quantify as many factors influence prices in these markets.

#### *CPG*

CPG competes directly with other interstate pipelines serving the Mid-Continent region. Indirectly, CPG competes with pipelines that transport Rocky Mountain gas to other markets. CPG has high interconnectivity at the Cheyenne Hub. The Cheyenne Hub is connected directly or indirectly to all major pipelines within the Rockies, which gather from all major producing basins in the region. CPG's interconnects near Greensburg, Kansas continue to benefit customers in the Mid-continent by continuing to provide increased reliability (due to pipeline diversity), increased optionality (due to supply basin diversity), and advantageous pricing (due to gas-on-gas competition). CPG's capacity to move Rockies production from the Cheyenne Hub area remains a vital link and along with sustained growth projections in Rockies production through 2022, CPG is well positioned to accommodate any future increase in Rockies production. In addition, CPG is ideally positioned to accommodate the expected surge in incremental production from associated gas within the high liquid content plays out of the Denver Basin.

#### *Elba Express*

Elba Express was originally designed to transport LNG supplies received by SLNG to markets in the southeast. However, the recent proliferation of gas production from shale formations has shifted the global LNG supply dynamics. With this shift, customers and potential customers of Elba Express have expressed a desire to displace supply from imported LNG with domestically produced natural gas. See Item 7 "Liquefaction Project" for further discussion regarding LNG exports. To that end, Elba Express is currently constructing facilities to effectuate transporting gas from domestic sources to markets in the southeast for a subsidiary of BG Group. These new facilities, which are anticipated to be in-service in the second quarter of 2013, will increase the capacity of Elba Express, which is currently completely subscribed under a long-term contract with a subsidiary of Shell. The new facilities will be subscribed under a long-term contract with a subsidiary of BG. Revenue from both of these contracts is predominantly based on reservation charges. As such, changes in throughput will have relatively little effect on our revenue stream or profitability. Global LNG economics will determine whether or not Elba Express receives supply from imported LNG, through SLNG. In the near term, it is not anticipated that SLNG will receive significant quantities of imported LNG.

### ***Regulatory Environment***

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. The FERC approves tariffs that establish rates, cost recovery mechanisms and other terms and conditions of service to our customers. The fees or rates established under our tariffs are a function of providing services to our customers, including a reasonable return on our invested capital. The FERC's authority also extends to:

- rates and charges for natural gas transportation, storage and related services;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipelines and certain affiliates;
- terms and conditions of services;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

### ***Safety Regulation***

We are subject to safety regulations imposed by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (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 (HCA), 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 United States 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 Act (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 protection of 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 cannot be accurately estimated at this time.

#### *Other Regulation*

Our interstate pipeline systems are also subject to other federal, state and local safety and environmental statutes and regulations of the United States Department of Transportation and the United States Department of the Interior. We have ongoing inspection programs designed to keep our facilities in compliance with pipeline safety and environmental requirements. For a further discussion of the potential impact of regulatory matters on us, see Item 1A "Risk Factors" and Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."

#### ***Our Relationship with El Paso and KMI***

El Paso, which is owned by KMI, primarily operates in the regulated natural gas transportation sector of the energy industry. KMI and its affiliates own our 2% general partner interest, all of our incentive distribution rights and a 41% limited partner interest in us.

KMI is the largest midstream and the third largest energy company in North America with a combined enterprise value of approximately \$100 billion. KMI owns an interest in or operates approximately 75,000 miles of pipelines and 180 terminals. KMI's pipelines transport natural gas, gasoline, crude oil, CO<sub>2</sub> and other products, and its terminals store petroleum products and chemicals and handle such products as ethanol, coal, petroleum coke and steel. KMI also owns the general partner and approximately 11% of the limited partner interests of Kinder Morgan Energy Partners, L.P., a publicly-traded MLP in North America.

As a substantial owner in us, KMI is motivated to promote and support the successful execution of our business strategies, including utilizing our partnership as a growth vehicle for its natural gas transportation, storage and other energy infrastructure businesses. Although we have the opportunity to make additional acquisitions directly from KMI in the future, KMI is under no obligation to make acquisition opportunities available to us. See Item 1A "Risk Factors" for additional information related to risks regarding KMI's ownership of our general partner.

#### ***Environmental Matters***

A description of our environmental remediation activities is included in Note 10 to our consolidated financial statements included elsewhere in this report.

#### ***Other***

##### *Employees*

We do not have employees. Employees of KMI and its affiliates provide services to our general partner, us and our subsidiaries. We are managed and operated by the directors and officers of our general partner. Under an omnibus agreement with El Paso and other policies with KMI and its affiliates, we reimburse KMI and its affiliates without a profit component for the provision of various general and administrative services for our benefit and for direct expenses incurred by KMI or its affiliates on our behalf. A further discussion of our affiliate transactions is included in Note 9 to our consolidated financial statements included elsewhere in this report.

*Properties*

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

*Available Information*

Our website is [www.kindermorgan.com](http://www.kindermorgan.com). We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after the reports are filed with the Securities and Exchange Commission (SEC). Information about each of the Board members of our general partner, as well as each of our general partner's Board's standing committee charters, our Corporate Governance Guidelines and our Code of Conduct are also available, free of charge, through our website. Information contained on our website is not part of this report.

**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.

**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 terms of sales on the drop-down of assets from KMI;
- price trends and overall demand for natural gas in the United States;
- 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 FERC;
- our ability to acquire new businesses and assets and integrate those operations into our existing operations, as well as our ability to expand our facilities;
- 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, ports, utilities, military bases or other businesses that could use our services or provide services or products to us;
- changes in natural gas production from exploration and production areas that we serve;
- 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;
- changes in accounting standards 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;
- our ability to offer and sell equity securities and debt securities or obtain debt financing in sufficient amounts to implement the 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;
- interruptions of electric power supply to our facilities due to natural disasters, power shortages, strikes, riots, terrorism (including cyber attacks), war or other causes;
- our ability to obtain insurance coverage without significant levels of self-retention of risk;

- acts of nature, accidents, sabotage, cyber attacks, terrorism or other similar acts causing damage greater than our insurance coverage limits;
- capital and credit markets conditions, inflation and interest rates;
- global political and economic stability;
- national, international, regional and local economic, competitive and regulatory conditions and developments;
- our ability to achieve cost savings and revenue growth;
- the timing and extent of changes in natural gas commodity prices;
- the ability to complete expansion projects on time and on budget;
- the timing and success of our business development efforts; and
- unfavorable results of litigation and the fruition of contingencies referred to in Note 10 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, financial condition or cash flows. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

### **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.

*The FERC may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC 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 the FERC allows us to recover in our rates or in our “negotiated rate” contracts, or to the extent that there is a lag before we can file and obtain rate increases, our operating results, cash flows and financial position 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. 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 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 could also 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, could 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 for compliance.*

We are subject to extensive laws and regulations related to pipeline integrity. There are, for example, federal guidelines for the United States Department of Transportation (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 found to be necessary. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipeline determined to be located in High Consequence Areas can have a significant impact on testing and repairs 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 United States 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.

*We may face competition from other pipelines and other forms of transportation into the areas we serve.*

Any current or future pipeline system or other form of transportation that delivers natural gas into the areas that our pipelines serve could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. To the extent that an excess of supply into these areas is created and persists, our ability to re-contract for expiring transportation capacity at favorable rates or otherwise to retain existing customers could be impaired. We also could experience competition for the supply of 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 expand our existing assets and construct new build projects, including joint venture projects. We may conduct from time to time alone or with others what are referred to as "open seasons" to evaluate the potential customer interest for new construction projects. 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.

Our interstate natural gas pipelines have federal eminent domain authority. However, 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 affected adversely by increased costs of capital or a reduction in the availability of credit.*

Adverse changes to the availability, terms and cost of capital, interest rates or our credit ratings could cause our cost of doing business to increase by limiting our access to capital, limiting our ability to pursue acquisition opportunities and reducing our cash flows. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Also, 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.

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

As of December 31, 2012, we had \$4.3 billion of consolidated debt. 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 such as 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 affect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 6 to our consolidated financial statements included elsewhere in this report.

*A breach of the covenants applicable to our debt and other financing obligations could affect our ability to borrow funds, could accelerate repayment of our debt and other financing obligations and those of our subsidiaries and reduce our cash available for distribution to our unitholders.*

Our debt and other financing obligations contain restrictive covenants and require us to maintain certain financial ratios, including debt to earnings before interest, income taxes, depreciation and amortization (EBITDA) and EBITDA to interest expense in our note purchase agreements and contain cross default provisions. Volatility in the financial markets and a reduction in access to capital could cause these covenants to become more restrictive over time. A breach of any of these covenants could preclude us or our subsidiaries from issuing letters of credit, from borrowing under our credit agreements and could accelerate our debt and other financing obligations and those of our subsidiaries. If this were to occur, we may not be able to repay such debt and other financing obligations.

*Restrictions in our credit facility and note purchase agreements could limit our ability to make distributions to our unitholders.*

Our credit facility and the note purchase agreement related to our issuance of senior unsecured notes contain covenants limiting our ability to make distributions to our unitholders and equity repurchases. Our ability to comply with any restrictions and covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If we are unable to comply with these restrictions and covenants, a significant portion of indebtedness outstanding under our credit facility or the note purchase agreement may become immediately due and payable, and our lenders' commitment to make further loans to us under our credit facility may terminate. We may not have, or be able to obtain, sufficient funds to make these accelerated payments. Our payment of principal and interest on any future indebtedness will reduce our cash available for distribution to our unitholders. Further, our credit facility limits our ability to pay distributions to our unitholders during an event of default or if an event of default results from the distribution.

*Our variable rate debt makes us vulnerable to increases in interest rates.*

Although a substantial portion of our debt capital structure has fixed interest rates, our revolving credit facility is variable rate debt, therefore changes in market conditions, including potential increases in the deficits of foreign, federal and state governments, could have a negative impact on interest rates that could cause our financing costs to increase. As of December 31, 2012, we had no borrowings outstanding on our revolving credit facility. Should we have an outstanding balance and 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."

*Our senior unsecured notes are obligations of El Paso Pipeline Partners Operating Company, L.L.C. (EPPOC) and not guaranteed by any of its subsidiaries. As such, the notes are effectively junior to EPPOC's existing and future secured debt and to all debt and other liabilities of its subsidiaries.*

The notes are EPPOC's unsecured obligations and rank equally in right of payment with all of its other existing and future unsubordinated debt. All of EPPOC's operating assets are in subsidiaries of EPPOC, and none of these subsidiaries guarantee EPPOC's obligations with respect to the notes. Creditors of EPPOC's subsidiaries have claims with respect to the assets of those subsidiaries that rank effectively senior to the notes. In the event of any distribution or payment of assets of such subsidiaries in any dissolution, winding up, liquidation, reorganization or other bankruptcy proceeding, the claims of those creditors would be satisfied prior to making any such distribution or payment to EPPOC in respect of its direct or indirect equity interests in such subsidiaries. Consequently, after satisfaction of the claims of such creditors, there may be little or no amounts left available to make payments in respect of the notes. As of December 31, 2012, the notes were effectively subordinated to approximately \$2.0 billion of outstanding indebtedness of EPPOC's subsidiaries. Furthermore, such subsidiaries are not prohibited under the indenture from incurring additional indebtedness.

In addition, because the notes and the guarantee of the notes by EPB are unsecured, holders of any secured indebtedness of EPPOC or EPB would have claims with respect to the assets constituting collateral for such indebtedness that are senior to the claims of the holders of the notes. Currently, neither EPPOC nor EPB have any secured indebtedness. Although the indenture governing the notes places some limitations on the ability of EPPOC to create liens securing debt, there are significant exceptions to these limitations, which allow us to secure significant amounts of indebtedness without equally and ratably securing the notes. If EPPOC or EPB incur secured indebtedness and such indebtedness is either accelerated or becomes subject to a bankruptcy, liquidation or reorganization, the assets of EPPOC or EPB would be used to satisfy obligations with respect to the indebtedness secured thereby before any payment could be made on the notes. Consequently, any such secured indebtedness would effectively be senior to the notes and the guarantee of the notes by EPB, to the extent of the value of the collateral securing the secured indebtedness. In that event, the noteholders may not be able to recover all the principal or interest that is due under the notes.

*We may not be able to generate sufficient cash to service all of our indebtedness, including the notes and our indebtedness under our revolving credit facility, and we may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.*

Our ability to make scheduled payments on or to refinance our debt obligations depends on our financial and operating performance, which is subject to prevailing economic and competitive conditions and to certain financial, business and other factors beyond our control. We cannot assure the noteholders that we will maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness. If our cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to reduce or delay capital expenditures, sell assets or operations, seek additional capital or restructure or refinance our indebtedness, including the notes. We cannot assure the noteholders that we would be able to take any of these actions, that these actions would be successful and would permit us to meet our scheduled debt service obligations or that these actions would be permitted under the terms of our existing or future debt agreements, including our credit agreement and the indenture that will govern the notes. In the absence of such cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our revolving credit facility contains restrictions on our ability to dispose of assets. We may not be able to consummate those dispositions or to obtain the proceeds that we could realize from them, and any proceeds may not be adequate to meet any debt service obligations when due.

*Our pipelines depend on certain key customers for a significant portion of their revenues and the loss of any of these key customers could result in a decline in our revenues. In addition, we are exposed to the credit risk of our counterparties and our credit risk management may not be adequate to protect against such risk.*

We are subject to the risk of our counterparties failing to make payments to us, which may include payments not being received within the time required under our contracts. Our current largest exposures are associated with shippers under long-term transportation contracts on our pipeline systems. Our systems rely on a limited number of customers for a significant portion of our systems' revenues. For the year ended December 31, 2012, the four largest customers for each of WIC, CIG, SNG, SLNG, Elba Express and CPG accounted for approximately 73%, 66%, 63%, 100%, 100% and 75% of their respective operating revenues. The creditworthiness of our customers may be adversely impacted by negative effects in the economy, including low natural gas prices which can reduce liquidity and cash flows for some of our customers that produce natural gas. The loss of all or a portion of the contracted volumes of these customers, as a result of competition, creditworthiness, inability to negotiate extensions, or replacements of contracts, could have a material adverse effect on us. Our credit procedures and policies that are governed by the FERC may not be adequate to fully eliminate counterparty credit risk. In addition, in certain situations, we may assume certain additional credit risks for competitive reasons or otherwise. If our existing or future counterparties fail to pay and/or perform, we could be adversely affected. For example, we may not be able to effectively remarket capacity during and after insolvency proceedings involving a customer. For additional information regarding our major customers, see Note 13 to our consolidated financial statements included elsewhere in this report.

*We depend on distributions from our subsidiaries to meet our needs.*

We have no significant assets other than our ownership interests in our operating subsidiaries. We are dependent on the earnings and cash flows, dividends, loans or other distributions from our subsidiaries to generate the funds necessary to meet our obligations. Applicable law and contractual restrictions (including restrictions in certain of our subsidiaries' credit facilities and the rights of certain creditors of our subsidiaries that would often be superior to our interests) may negatively impact our ability to obtain such distributions from our subsidiaries.

The amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from working capital or other borrowings, and not solely on profitability, which will be affected by non-cash items. As a result, we may increase cash distributions during periods when we experience reductions in net income for financial accounting purposes and may reduce cash distributions during periods when we experience increases in net income for financial accounting purposes.

*Our acquisition strategy and expansion programs require access to new capital. Tightened capital markets or more expensive capital could 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. Limitations on our access to capital could impair our ability to execute this strategy.

*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.*

Part of our business strategy includes acquiring additional businesses, 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 companies that have previously operated separately involves a number of risks, including (i) demands on management related to the increase in our size after an acquisition, expansion or completed construction project; (ii) the diversion of management's attention from the management of daily operations; (iii) difficulties in implementing or unanticipated costs of accounting, estimating, reporting and other systems; (iv) difficulties in the assimilation and retention of necessary employees; and (v) potential adverse effects on operating results.

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. 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.

*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 the Comprehensive Environmental Response, Compensation, and Liability Act (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 such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

Further, we cannot ensure that such existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects. For more information, see Note 10 to our consolidated financial statements included elsewhere in this report.

*Climate change regulation at the federal, state, 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 United States EPA began regulating the greenhouse gas emissions requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources, fractionated natural gas liquids and from certain stationary sources.

Because our operations, including our compressor stations and natural gas processing plants 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 may require us to install new emission controls equipment at our facilities, acquire allowances for our greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and/or 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.

*Increased regulation of exploration and production activities, including hydraulic fracturing, could result in reductions or delays in drilling and completing new natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas transported on our 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. Natural gas extracted 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 natural gas exploration and production operators in the completion of certain natural 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 natural gas from areas in which the use of hydraulic fracturing is prevalent.

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

The United States 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.

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

Our pipelines depend on production of natural gas 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. 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 a level 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 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 natural gas producing areas. In addition, changes in the regulatory environment or governmental policies may have an impact on the supply of 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 natural gas 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 natural gas 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 natural gas industry could reduce demand for natural gas, increase our costs and may 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.

*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 natural gas industry 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. 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. If global economic and market conditions 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 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 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.

*There are accounting principles that are unique to regulated interstate pipeline assets that could materially impact our recorded earnings.*

Accounting policies for FERC regulated pipelines are in certain instances different from United States GAAP for nonregulated entities. For example, we are required to record certain regulatory assets on our balance sheet that would not be recorded for nonregulated entities. In determining whether to account for regulatory assets on each of our pipelines, we consider various factors including regulatory changes and the impact of competition to determine the probability of recovery of these assets. Currently, all of our pipeline systems have regulatory assets recorded on their balance sheets. If we determine that future recovery is no longer probable for any of our pipeline systems, then we could be required to write off the regulatory assets in the future. In addition, we capitalize a carrying cost (an allowance for funds used during construction or AFUDC) on equity funds related to our construction of long-lived assets. Equity amounts capitalized are included as "Other income, net" on our Consolidated Statements of Income. We periodically evaluate the applicability of accounting standards related to regulated operations, and consider factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, we may have to evaluate our assets for impairment and write-off the associated regulatory assets and our future earnings could be impacted.

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

We are managed and operated by KMI and its affiliates. Such operations and management require the retention and recruitment of a skilled workforce including engineers, technical personnel and other professionals. KMI competes with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible, which have significant institutional knowledge that must be transferred to other employees. If KMI is unable to (a) retain their current employees, (b) successfully complete the knowledge transfer and/or (c) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased allocated costs to retain and recruit these professionals.

### **Risks Inherent in Our Structure and Relationship with KMI**

*Our ability to continue to acquire interests in interstate pipelines from KMI could be negatively impacted by various factors that would reduce our growth opportunities.*

An important source of our growth in the past and potentially in the future is the purchase of interests in interstate pipelines from our parent and its subsidiaries. Our general partner is entitled to incentive distribution rights (IDRs), which are currently at the maximum level. As owner of our general partner, KMI ultimately benefits from these IDRs. Our ability to purchase additional interests on an accretive basis to the limited partner unitholders may be negatively impacted by such IDRs unless KMI causes our general partner to reduce the level of the IDRs as provided for in the partnership agreement. In addition, as the owner of the general partner of the partnership, KMI could also be subject to claims associated with conflicts of interest and breach of fiduciary duties. Although the partnership agreements expressly define and limit the obligations of our general partner, if any conflicts of interest or breach of fiduciary duties are found, then our ability to purchase additional interests in interstate pipeline assets from KMI could be negatively impacted.

*We do not have the same flexibility as other types of organizations to accumulate cash, which may limit cash available to make distributions to unitholders and otherwise conduct our business.*

Unlike a corporation, our partnership agreement requires us to distribute, on a quarterly basis, 100% of its available cash to our unitholders of record and our general partner. Available cash is generally defined as all of our cash-on-hand as of the end of a fiscal quarter, adjusted for cash distributions and net changes to reserves. Our general partner will determine the amount and timing of such distributions and has broad discretion to establish and make additions to its reserves or the reserves of our operating subsidiaries in amounts it determines in its reasonable discretion to be necessary or appropriate:

- to provide for the proper conduct of our business and the businesses of our operating subsidiaries (including reserves for future capital expenditures and for our anticipated future credit needs);
- to reimburse our general partner for all expenses it has incurred on our behalf;
- to provide funds for distributions to our unitholders and its general partner for any one or more of the next four calendar quarters; or
- to comply with applicable law or any of our loan or other agreements.

*KMI controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including KMI, have conflicts of interest with us and limited fiduciary duties and they may favor their own interests, including their interest in Kinder Morgan Energy Partners, L.P. (KMP), to the detriment of our unitholders.*

KMI owns and controls our general partner, and appoints all of the directors of our general partner. Some of our general partner's directors, and some of its executive officers, are directors or officers of KMI or its affiliates. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to KMI. Therefore, conflicts of interest may arise between KMI and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders.

*Affiliates of our general partner, including KMI and its other subsidiaries, are not limited in their ability to compete with us and are not obligated to offer us the opportunity to pursue additional assets or businesses, which could limit our commercial activities or our ability to acquire additional assets or businesses.*

Neither our partnership agreement nor the omnibus agreement among us, El Paso and others will prohibit affiliates of our general partner, including KMP, from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, KMI and its affiliates may acquire, construct or dispose of additional transportation or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. KMI and KMP are established participants in the interstate pipeline and/or storage business, and each may have greater resources than we have, which factors may make it more difficult for us to compete with these entities with respect to commercial activities as well as for acquisition candidates. As a result, competition from these entities could adversely impact us.

*Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which the common units will trade.*

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will not elect our general partner or its board of directors, and will have no right to elect our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner, including the independent directors, will be chosen entirely by its owners and not by the unitholders. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at such annual meetings of stockholders. Furthermore, if the unitholders were dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

*Cost reimbursements to our general partner and its affiliates for services provided, which will be determined by our general partner, will be substantial and will reduce our cash available for distribution.*

Pursuant to an omnibus agreement and other policies we have with El Paso, KMI and its affiliates and our general partner, we will reimburse KMI and its affiliates for the payment of operating and capital expenses related to our operations and for the provision of various general and administrative services for our benefit, including costs for rendering administrative staff and support services to us, and overhead allocated to us, including pension and health care costs which amounts will be determined by KMI and its affiliates in good faith. Payments for these services will be substantial and will reduce the amount of cash available for distribution to unitholders. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

*Our partnership agreement limits our general partner's fiduciary duties to holders of our common units and restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.*

Our partnership agreement contains provisions that reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty laws. The limitation and definition of these duties is permitted by the Delaware law governing limited partnerships. The defined fiduciary standards are more limited than those that would apply under Delaware law in the absence of such definition.

*Unitholders cannot remove our general partner without its consent.*

The vote of the holders of at least 66<sup>2/3</sup>% of all outstanding common units voting together as a single class is required to remove our general partner. Our unitholders are currently unable to remove our general partner without its consent because affiliates of our general partner own sufficient units to be able to prevent the general partner's removal. In addition, under certain circumstances the successor general partner may be required to purchase the combined general partner interest and incentive distribution rights of the removed general partner, or alternatively, such interests will be converted into common units.

*Our general partner may elect to cause us to issue Class B common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or holders of our common units. This may result in lower distributions to holders of our common units in certain situations.*

Our general partner holds all of our incentive distribution rights which provide the right to elect to relinquish the receipt of incentive distribution payments based on the initial cash target distribution levels and to reset (on the satisfaction of certain conditions) minimum quarterly and cash target distributions at higher levels that the general partner would be entitled to receive. In connection with resetting these target distribution levels, our general partner would be entitled to receive a number of Class B common units. The Class B common units would be entitled to the same cash distributions per unit as our common units and would be convertible into an equal number of common units.

In April 2012, the conditions were met which entitled our general partner to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are set. The reset election has not been made, however we anticipate that our general partner will exercise the right in the future to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It however, is possible that our general partner could exercise this reset election at a time when it is experiencing, or may be expected to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B common units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B common units to our general partner in connection with resetting the target distribution levels related to our general partner incentive distribution rights.

*The control of our general partner may be transferred to a third party without unitholder consent.*

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the members of our general partner from transferring their member interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of the general partner with their own choices and to control the decisions taken by the board of directors and officers of the general partner. This effectively permits a change of control of the partnership without unitholders' vote or consent.

*We may issue additional units without approval which would dilute existing ownership interests.*

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- each unitholder's proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;

- the ratio of taxable income to distributions may increase;
- new classes of securities could be issued that provide preferences to the new class in relation to existing unitholders, including preferences on distributions of available cash, distributions upon our liquidation and voting rights;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

*Our general partner has a limited call right that may require unitholders to sell common units at an undesirable time or price.*

If at any time our general partner and its affiliates own more than 75% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders would be required to sell common units at an undesirable time or price and may not receive any return on investment. Unitholders might also incur a tax liability upon a sale of such units.

Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we may no longer be subject to the reporting requirements of the Securities Exchange Act of 1934. Our general partner and its affiliates own approximately 41% of our outstanding common units at December 31, 2012.

*Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.*

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner and its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. The partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders ability to influence the manner or direction of management.

*Unitholder liability may not be limited if a court finds that unitholder action constitutes control of our business.*

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. Unitholders could be liable for any and all of our obligations as if they were a general partner if a court or government agency determined that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- unitholders' right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

*The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets, including sales by affiliates of our general partner.*

As of January 31, 2013, we had 215,789,325 common units outstanding, which includes 90,320,810 common units held by affiliates of our general partner. Sales by any of our existing unitholders, including affiliates of our general partner, of a substantial number of our common units in the public markets, or the perception that such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. Under our partnership agreement, our general partner and its affiliates have registration rights relating to the offer and sale of any units that they hold, subject to certain limitations.

*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.

### **Tax Risks to Common Unitholders**

*Our tax treatment depends on our status as a partnership for United States federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for United States 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 United States federal income tax purposes. To maintain our status as a partnership for United States federal income tax purposes, current law requires that 90% or more of our gross income for every taxable year consist of “qualifying income,” as defined in Section 7704 of the Internal Revenue Code of 1986, as amended, which we refer to as the Code. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service, which we refer to as the IRS, on this or any other matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible under certain circumstances for such an entity to be treated as a corporation for United States federal income tax purposes. If we were to be treated as a corporation for United States federal income tax purposes, we would pay United States federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would pay state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a 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 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 amount of distributions we pay, and in the value of our common units.

Current law or our business may change, causing us to be treated as a corporation for United States federal income tax purposes or otherwise subjecting us to entity-level taxation. Members of Congress are considering substantive changes to the existing United States federal income tax laws that could affect the tax treatment of certain publicly-traded partnerships. For example, federal income tax legislation recently has been considered by Congress that would eliminate partnership tax treatment for certain publicly-traded partnerships. Although the legislation most recently considered by Congress would not appear to affect our tax treatment as a partnership for United States federal income tax purposes, we are unable to predict whether any other proposals will ultimately be enacted. Any such changes could negatively impact our cash flows and the value of our common units.

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, we are now subject to an entity-level tax on the portion of our total revenue that is generated in Texas. Specifically, the Texas margin tax is imposed at a maximum effective rate of 0.7% of our gross income that is apportioned to Texas. This tax reduces, and the imposition of such a tax on us by another state will reduce, the cash available for distribution to our common unitholders.

Our partnership agreement provides that if a law is enacted that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for United States federal income tax purposes, the minimum quarterly distribution and the target distribution levels will be adjusted to reflect the impact of that law on us.

*The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.*

The present United States federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the United States federal income tax laws or interpretations thereof may or may not be applied retroactively. Although we are unable to predict whether any of these changes or any other proposals will ultimately be enacted, any changes could negatively impact the value of an investment in our common units.

*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.*

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 use of this proration method may not be permitted under existing Treasury Regulations, and, 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.

*If the IRS contests the United States federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our common unitholders.*

We have not requested a ruling from the IRS with respect to our treatment as a partnership for United States federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take. 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 the positions we take. Any contest with the IRS 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 common unitholders and our general partner 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 which could be different in amount than the cash we distribute, they are required to pay any United States federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they do not receive any 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 that results from that income.

*Tax gain or loss on 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 decrease 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 a gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized may include a common unitholder's share of our nonrecourse liabilities, if a unitholder sells its common units, such unitholder may incur a tax liability in excess of the amount of cash received from the sale.

*Tax-exempt entities and non-United States 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-United States persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from United States federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non- United States persons will be reduced by withholding taxes imposed at the highest applicable effective tax rate, and non- United States persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. Any tax-exempt entity or non-United States person should consult its tax adviser before investing in our common units.

*Our treatment of a purchaser of common units as having the same tax benefits as the seller could be challenged, resulting in a reduction in value of our common units.*

Because we cannot match transferors and transferees of common units, we are required to maintain the uniformity of the economic and tax characteristics of these common units in the hands of the purchasers and sellers of these common units. We do so by adopting certain depreciation conventions that do not conform to all aspects of the United States Treasury regulations. A successful IRS challenge to these conventions could adversely affect the tax benefits to a common unitholder of ownership of our common units and could have a negative impact on the value of our common units or result in audit adjustments to a common unitholder's tax returns.

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.

*We adopted certain valuation methodologies that 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 current valuation methods, subsequent purchasers of common units may have a greater portion of their adjustment under Section 743(b) of the Code 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 adjustment under Section 743(b) of the Code attributable to our tangible and intangible assets, and allocations of 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 United States federal income tax purposes.*

We will be considered to have terminated for United States 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 any twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a significant 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 fiscal year ending December 31, 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. Our termination currently would not affect our classification as a partnership for United States federal income tax purposes, but instead, we would be treated as a new partnership for 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.

*A common unitholder whose common units are loaned to a “short seller” to cover a short sale may be considered as having disposed of those common units. If so, the common unitholder would no longer be treated for United States 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 cover a short sale may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for United States 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 cover 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.

*As a result of investing in our common units, a common unitholder may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.*

In addition to United States federal income taxes, our common unitholders will likely be subject to other taxes, including 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 state and local income tax returns and pay 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. It is the responsibility of each common unitholder to file all required United States federal, state and local tax returns. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in our common units.

**ITEM 1B. *Unresolved Staff Comments.***

None.

**ITEM 3. *Legal Proceedings.***

See Note 10 to our consolidated financial statements included elsewhere in this report.

**ITEM 4. *Mine Safety Disclosures.***

Not applicable.

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

Our common units are traded on the New York Stock Exchange under the symbol EPB. As of January 31, 2013, we had 39 unitholders of record, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

The following table reflects the quarterly high and low sales prices for our common units based on the daily composite listing of stock transactions for the New York Stock Exchange and the cash distributions per unit we declared in each quarter:

	High	Low	Distributions per Unit
<b>2012</b>			
Fourth Quarter	\$ 38.65	\$ 33.64	\$ 0.58
Third Quarter	37.43	33.26	0.55
Second Quarter	35.42	30.64	0.51
First Quarter	38.10	33.34	0.50
<b>2011</b>			
Fourth Quarter	\$ 38.09	\$ 31.81	\$ 0.49
Third Quarter	38.36	31.36	0.48
Second Quarter	37.56	32.34	0.46
First Quarter	38.00	32.98	0.44

***Cash Distributions***

Our partnership agreement requires us to distribute all of our cash on hand at the end of each quarter, less reserves established by our general partner. We refer to this cash as “available cash.” See Note 8 to our consolidated financial statements included elsewhere in this report for further information regarding distributions. On February 14, 2013, we paid a distribution of \$0.61 per unit to all unitholders of record at the close of business on January 31, 2013. Our general partner received incentive distributions of \$105 million and \$49 million in 2012 and 2011, respectively. On February 14, 2013 our general partner received an incentive distribution of \$43 million.

***Other***

See Note 8 to our consolidated financial statements included elsewhere in this report for additional information related to the incentive distribution rights of our general partner and the conversion of subordinated units into common units effective January 3, 2011.

**ITEM 6. Selected Financial Data.**

The operating results data for each of the three years ended December 31, 2012 and financial position data as of December 31, 2012 and 2011 were derived from our audited financial statements. We derived the operating results data for each of the two years ended December 31, 2009 and the financial position data as of December 31, 2010, 2009 and 2008 from our accounting records. As a result of the May 2012 acquisition, as discussed in Note 3 to our consolidated financial statements included elsewhere in this report, we had the ability to control CPG's operating and financial decisions and policies. Accordingly, we have retrospectively adjusted our historical financial statements in all periods presented to reflect the reorganization of entities under common control and the change in reporting entity. The selected financial data is not necessarily indicative of results to be expected in future periods and should be read together with Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 15 "Exhibits and Financial Statement Schedules" included elsewhere in this report.

	As of or for the Year Ended December 31,				
	2012	2011	2010	2009	2008
(In Millions, Except Per Unit Amounts)					
<b>Operating Results Data:</b>					
Revenues	\$ 1,515	\$ 1,531	\$ 1,454	\$ 1,231	\$ 1,173
Operating income	863	849	819	656	605
Net income	589	605	666	542	507
Net income attributable to El Paso Pipeline Partners, L.P.	579	512	418	357	333
Net income attributable to El Paso Pipeline Partners, L.P. per limited partner unit-basic and diluted:					
Common units	2.15	2.03	1.90	1.64	1.26
Subordinated units <sup>(1)</sup>	—	—	1.78	1.56	1.12
Per unit cash distributions declared during the period	2.14	1.87	1.55	1.33	1.01
<b>Balance Sheet Data (at end of period):</b>					
Property, plant and equipment, net	\$ 5,931	\$ 6,040	\$ 6,051	\$ 5,781	\$ 5,182
Total assets	6,581	6,679	6,569	6,565	6,034
Long-term debt and other financing obligations, less current maturities	4,246	4,028	3,580	2,732	2,478

<sup>(1)</sup> All subordinated units were converted into common units on a one-for-one basis effective January 3, 2011. See Note 8 to our consolidated financial statements included elsewhere in this report for further information.

## **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 this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2 "Business and Properties" and (ii) a description of risk factors affecting us and our business, found in Item 1A "Risk Factors."

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

### ***General***

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

- helping customers by providing transportation and storage of natural gas; 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 natural gas pipelines, related storage facilities and an LNG terminal.

Our revenues 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. Our long-term transportation 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. Our LNG terminal capacity is similarly subscribed under long-term contracts, which are based on reservation charges (with little impact by changes in throughput at the terminal). As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas.

### ***Our Business***

We are a Delaware master limited partnership formed in 2007 to own and operate interstate natural gas transportation, storage and terminaling facilities. We own WIC, CIG, SLNG, Elba Express, SNG and CPG. Our primary business consists of interstate transportation and storage of natural gas. Our pipeline operations are rate-regulated and accordingly we generate profit based on our ability to earn a return in excess of our costs through the rates we charge our customers.

### ***Factors influencing profitability***

Our long-term profitability will be influenced primarily by the following factors:

- Executing successfully on our expansion projects and developing growth projects in our market and supply areas;
- Contracting and recontracting pipeline capacity with our customers;
- Maintaining or obtaining approval by the FERC of acceptable rates, terms of service and expansion projects;
- Improving operating efficiency; and
- Pursuing strategic asset acquisitions from KMI and third parties to grow our business.

**Types of Revenue**

Each of our subsidiaries faces varying degrees of competition from other existing and proposed pipelines and LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil.

Our revenues consist of the following types:

<u>Type</u>	<u>Description</u>	<u>Percent of Total Revenues in 2012<sup>(1)</sup></u>						<u>EPB Consolidated</u>
		<u>WIC</u>	<u>CIG</u>	<u>SLNG</u>	<u>Elba Express</u>	<u>SNG</u>	<u>CPG</u>	
Reservation	Reservation revenues are from customers (referred to as firm customers) that reserve capacity on our pipeline systems and storage facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts.	98%	93%	90%	100%	89%	100%	93%
Usage and Other	Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) that pay usage charges based on the volume of gas actually transported, stored, injected or withdrawn.	2%	7%	10%	—	11%	—	7%

(1) Excludes liquids transportation revenue and fuel sales. In the case of CIG, liquids revenue associated with CIG's processing plant is also excluded. The revenues described in this table constitute approximately 99% of EPB's, 95% of CIG's and 100% of WIC's, SLNG's, Elba Express', SNG's and CPG's total revenues.

The FERC regulates the rates we can charge our customers. These rates are generally a function of the cost of providing services to our customers, including a reasonable return on our invested capital. Because of our regulated nature and the high percentage of our revenues attributable to reservation charges, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices, changes in supply and demand, regulatory actions, competition, declines in the creditworthiness of our customers and weather.

We continue to manage the process of renewing expiring contracts to limit the risk of significant impacts on revenues. The contracts mature at various times and in varying amounts of throughput capacity. The ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and the 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. We attempt to recontract or remarket capacity at the maximum rates allowed under their respective tariffs, although at times, we enter into firm transportation contracts at amounts that are less than these maximum allowable rates to remain competitive. The extent that these amounts are less than the maximum rates varies for each of our pipeline systems. As of December 31, 2012, the remaining weighted average contract life of our natural gas transportation and LNG contracts was approximately 8 years and 20 years, respectively.

**Summary of 2012 Performance**

During 2012, we continued to deliver solid operational performance. We acquired the remaining 14% interest in CIG and a 100% interest in CPI, which owns CPG, from El Paso for an aggregate \$635 million. See Note 3 to our consolidated financial statements included elsewhere within this report for additional information related to these acquisitions.

During 2012, we generated significant earnings and continued to focus on delivering our expansion projects. In June 2012, SNG placed Phase III of the South System III Expansion project into service. In addition, KMI's acquisition of El Paso became effective on May 25, 2012.

## **Growth Projects**

### *South System III*

The South System III project expanded the SNG pipeline system in Mississippi, Alabama and Georgia by adding approximately 81 miles of pipeline looping and replacement on SNG's south system and 17,310 horsepower of compression to serve an existing power generation facility owned by Southern Company in the Atlanta, Georgia area that is being converted from coal fired to cleaner burning natural gas. This expansion project was comprised of three phases, with each phase adding an additional 122 MMcf/d of capacity. Phases I, II and III were placed into service on time and under budget in January 2011, June 2011, and June 2012, respectively.

### *Elba Express Phase B Expansion*

The Elba Express Phase B expansion will add 10,000 horsepower at a new compressor station located in Hart County, Georgia. This expansion will allow for Elba Express to receive 220 MMcf/d of natural gas supplies from existing interconnections with Transcontinental Gas Pipe Line Company, LLC for deliveries to markets in the southeast. The expansion is anticipated to be in-service in the second quarter of 2013.

### *Elba Express Modification*

In January 2013, Shell LNG entered into a precedent agreement with Elba Express pursuant to which Elba Express will modify its facilities to transport natural gas to the Elba Island terminal for liquefaction and export as further discussed under "Liquefaction Project" below.

We continue to evaluate additional expansion opportunities around our assets. We have other prospective projects that are in various phases of commercial development. Many of these potential projects involve expansion capacity to serve increased natural gas-fired generation loads or to adapt to changing supply profiles resulting from burgeoning shale gas development, declines in LNG imports and potential LNG exports, and would have in-service dates from 2014 and beyond. If we are successful in contracting for these new loads, the capital requirements could be substantial and would be incremental to our contracted growth projects. Although we pursue the development of these potential projects from time to time, there can be no assurance that we will be successful in negotiating the definitive binding contracts necessary for such projects to be included in our contracted growth projects.

## **Liquefaction Project**

In June 2012, SLNG received authorization from the Department of Energy (DOE) to export domestically produced LNG of up to 4 million tonnes per year (equivalent to approximately 0.5 Bcf of natural gas per day) to countries with which the United States has a free trade agreement (FTA). In August 2012, SLNG filed an application with the DOE requesting authorization to export up to 4 million tonnes per year of LNG from the Elba Island LNG terminal. The authorization would allow the export of LNG from the terminal to any non FTA country.

In January 2013, Southern Liquefaction Company, LLC (SLC), a unit of EPB, and Shell US Gas & Power LLC (SUSGP), a subsidiary of Royal Dutch Shell plc, announced plans to develop a natural gas liquefaction plant in two phases at SLNG. SLC will own 51% of the entity and SUSGP will own the remaining 49%. SLNG will modify its facilities at Elba Island and will operate the facility. Phase I of the project, approximately 210 Mmcf/d (1.5 million tonnes per year), requires no additional DOE approval.

## ***Results of Operations***

### *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. Because we distribute all of our available cash to investors, our primary objective is to grow cash distributions over time. We believe the primary measure of company performance used by us, investors and industry analysts covering MLPs is cash generation performance. Therefore, we believe DCF is our most important measure to evaluate the operating and financial performance of the partnership and to compare it with the performance of other publicly traded MLPs within the industry.

Subsequent to KMI's acquisition of El Paso, our definition of DCF has been conformed to KMP's definition. We now define DCF before certain items to be limited partners' income before certain items and depreciation and amortization (DD&A), less sustaining capital expenditures, plus our share of DD&A less our share of sustaining capital expenditures for Bear Creek and WYCO, our equity method investees, plus other income and expenses, net (which primarily includes deferred revenue, allowance for funds used during construction (AFUDC) equity and other non-cash items).

Our DCF was \$590 million, \$483 million and \$389 million for the years ended December 31, 2012, 2011 and 2010, respectively. The increase in DCF of \$107 million in 2012 as compared to 2011 was primarily due to our acquisition of CPG, increased ownership interests in SNG and CIG as a result of our acquisitions in 2011 and 2012 and a decrease in sustaining capital expenditures. Our increase in DCF of \$94 million in 2011 as compared to 2010 was primarily driven by higher expansion revenues and our increased ownership interest in SLNG, Elba Express, CIG and SNG.

The table below details the reconciliation of DCF to Net Income (in millions).

	Year Ended December 31,		
	2012	2011	2010
Net Income	\$ 589	\$ 605	\$ 666
Net income attributable to noncontrolling interests	(10)	(93)	(248)
Net income attributable to El Paso Pipeline Partners, L.P.	579	512	418
Certain items:			
CPG pre-acquisition earnings	(22)	(40)	(40)
Project cancellation payment	—	(14)	—
Loss on write-off of asset	11	—	—
CIG environmental reserve adjustment	(6)	—	—
Non-cash severance costs <sup>(1)</sup>	34	—	—
Amortization of regulatory asset related to offshore asset sale	2	—	—
Non-cash asset write down on sale of assets	—	—	21
Subtotal certain items	19	(54)	(19)
Net income attributable to El Paso Pipeline Partners, L.P. before certain items	598	458	399
Less: General Partner's 2% interest allocation	(12)	(9)	(6)
General Partner's incentive distribution	(129)	(62)	(14)
Limited Partners' Net Income before certain items	457	387	379
Add/(Subtract):			
Depreciation and amortization <sup>(2)</sup>	176	169	153
Net income attributable to noncontrolling interests before certain items	10	79	227
Declared distributions to noncontrolling interests before certain items	(8)	(47)	(248)
Sustaining capital expenditures <sup>(2)</sup>	(46)	(103)	(95)
Other, net <sup>(3)</sup>	1	(2)	(27)
	133	96	10
Distributable Cash Flow before certain items—Limited Partners	\$ 590	\$ 483	\$ 389

- (1) The 2012 amount reflects the non-cash severance costs allocated to us from El Paso as a result of KMI's acquisition of El Paso; however, we do not have any obligation nor did we pay any amounts related to this expense.
- (2) Includes our share of Bear Creek and WYCO depreciation and amortization or sustaining capital expenditures.
- (3) Includes deferred revenue and certain non-cash items such as AFUDC equity and other items.

### *Earnings Results*

We previously reported earnings before interest expense and income taxes as our segment performance measure. As a result of KMI's acquisition of El Paso, management now assesses our segment performance based on EBDA, which excludes depreciation and amortization, general and administrative expenses and interest expense, net. Certain general and administrative expenses have been excluded from EBDA such as employee benefits, legal, information technology and other costs that are not controllable by operating management and thus are not included in the measure of performance for which they are accountable. Our management uses EBDA as a measure to assess the operating results and effectiveness of our assets, which consists of both consolidated operations and earnings from equity method investments. We believe providing EBDA to our investors is useful because it is the same measure used by management to evaluate our segment performance and allows investors to evaluate our operating results without regard to our financing methods or capital structure. EBDA may not be comparable to measures used by other companies. Additionally, EBDA should be considered in conjunction with net income and other performance measures such as operating income or operating cash flows.

Below is a reconciliation of our EBDA to net income attributable to EPB for the annual periods presented (in millions):

	2012	2011	2010
EBDA <sup>(1)(2)(3)</sup>	\$ 1,202	\$ 1,184	\$ 1,160
Depreciation and amortization <sup>(4)</sup>	(181)	(180)	(165)
General and administrative expenses <sup>(5)</sup>	(139)	(132)	(128)
Interest and debt expense, net <sup>(6)</sup>	(293)	(267)	(199)
Income tax expense	—	—	(2)
Net income	589	605	666
Net income attributable to noncontrolling interests	(10)	(93)	(248)
Net income attributable to EPB	<u>\$ 579</u>	<u>\$ 512</u>	<u>\$ 418</u>

- (1) 2012 includes a \$27 million increase in EBDA for certain items as follows:
- \$34 million of pre-acquisition EBDA related to CPG,
  - \$11 million charge to operating expenses attributable to a canceled software implementation project,
  - \$6 million non-cash adjustment to reduce environmental liabilities for certain CIG environmental projects, and
  - \$2 million amortization of regulatory assets associated with the SNG offshore asset sale.
- (2) 2011 includes a \$99 million increase in EBDA for certain items as follows:
- \$85 million of pre-acquisition EBDA related to CPG,
  - \$17 million of revenue resulting from BG LNG's cancellation of its commitment to Phase B of SLNG's Elba III Expansion, and
  - \$3 million charge to operating expenses due to the write-off of project development costs incurred in conjunction with the aforementioned Elba Express expansion project.
- (3) 2010 includes a \$72 million increase in EBDA for certain items as follows:
- \$93 million of pre-acquisition EBDA related to CPG, and
  - \$21 million non-cash write down based on a FERC order related to the 2009 sale of the CIG Natural Buttes facilities (compressor station and gas processing plant).
- (4) Includes pre-acquisition depreciation and amortization expense for CPG of \$5 million in 2012 and \$12 million for each of 2011 and 2010.
- (5) Includes certain items as follows:
- pre-acquisition general and administrative expenses for CPG of \$3 million in 2012 and \$8 million for each of 2011 and 2010, and
  - non-cash severance costs of \$34 million in 2012 allocated to us from El Paso as a result of KMI's acquisition of El Paso; however, we do not have any obligation nor did we pay any amounts related to this expense.
- (6) Includes pre-acquisition interest and debt expense, net for CPG of \$4 million, \$11 million and \$12 million in 2012, 2011 and 2010, respectively.

Below are the components of EBDA, our throughput volumes and an analysis and discussion of our operating results for the annual periods presented (in millions, except operating statistics).

	2012	2011	2010
Revenues	\$ 1,515	\$ 1,531	\$ 1,454
Operating Expenses	(332)	(370)	(342)
Earnings from equity investments	14	15	16
Other income, net	5	8	32
<b>EBDA</b>	<b>\$ 1,202</b>	<b>\$ 1,184</b>	<b>\$ 1,160</b>
Throughput volumes (BBtu/d) <sup>(7)</sup>	<u>7,864</u>	<u>7,364</u>	<u>7,694</u>

(7) Throughput volumes are presented for WIC, CIG, SNG and CPG and exclude intrasegment volumes. The average daily volumes transported on Elba Express during 2012, 2011 and 2010 were not material.

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

*EBDA*

The items described above in footnotes (1) and (2) decreased our EBDA by \$72 million for 2012 as compared to 2011. After adjusting for these items, our EBDA increased by \$90 million as compared to 2011 primarily due to the following:

- The CPG acquisition contributed \$51 million of incremental EBDA for the year ended December 31, 2012 (reflecting CPG's EBDA results for the May 25 to December 31, 2012 post-acquisition period). See Note 3 to our consolidated financial statements included elsewhere in this report for additional information regarding the acquisition of CPG;
- SNG contributed higher EBDA of \$26 million primarily due to the completion of Phases II and III of the South System III expansion project in June 2011 and June 2012;
- CIG contributed additional EBDA of \$6 million in 2012 as compared to 2011 largely due to favorable property tax adjustments of \$4 million during 2012, lower pipeline maintenance, payroll and contractor costs of \$10 million and increased reservation revenue of \$7 million related to an expansion project placed in service in October 2011. Partially offsetting these favorable impacts were lower transportation revenues of \$15 million primarily resulting from the non renewal of expiring contracts, the restructuring of certain contracts at lower volumes or discounted rates and lower usage and interruptible revenues due to milder weather; and
- WIC contributed additional EBDA of \$4 million in 2012 as compared to 2011 primarily due to higher expenses related to compressor station repairs performed in 2011.

*Depreciation and Amortization*

After adjusting for the items described in footnote (4) above, our depreciation and amortization expense was \$8 million higher in 2012 as compared to 2011 primarily due to increased property, plant and equipment additions related to expansion projects placed in service during 2012 and 2011.

*General and Administrative Expenses*

After adjusting for the items described in footnote (5) above, general and administrative expenses were \$22 million lower in 2012 as compared to 2011 primarily due to lower benefit costs resulting from acquisition-related employee headcount reductions.

*Interest and Debt Expense, net*

After adjusting for the items described in footnote (6) above, interest and debt expense, net, increased by \$33 million in 2012 as compared to 2011 primarily due to higher average debt outstanding used to fund acquisitions and expansion projects. The increase in our average debt outstanding was attributable to the revolving credit facility borrowings to fund the May 2012 CPG acquisition, the November 2012 issuance of \$475 million senior notes by EPPOC, the debt issuances of \$500 million senior notes by EPPOC in September 2011 and \$300 million senior notes by SNG in June 2011. For a further discussion of these debt obligations, see Note 6 to our consolidated financial statements included elsewhere in this report.

*Net Income Attributable to Noncontrolling Interests*

Our net income attributable to noncontrolling interests decreased in 2012 as compared to 2011 primarily due to our acquisition of incremental interests in SNG and CIG in 2011 and 2012.

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

*EBDA*

The items described above in footnotes (2) and (3) increased our EBDA by \$27 million for 2011 as compared to 2010. After adjusting for these items, our EBDA decreased by \$3 million as compared to 2010 primarily due to the following:

- SNG contributed higher EBDA of \$3 million. Our EBDA was favorably impacted by \$23 million due to the completion of Phases I and II of the South System III expansion project in January and June 2011. Partially offsetting this favorable impact were lower transportation revenues of \$14 million primarily resulting from the restructuring of certain contracts at lower volumes or discounted rates and lower usage and interruptible revenues due to milder weather. EBDA was further burdened by \$6 million during 2011 as compared to 2010 primarily due to an unfavorable gas balance revaluation resulting from lower prices and higher retained volumes and the elimination of their fuel sharing mechanism;
- CIG's EBDA decreased by \$8 million in 2011 as compared to 2010. Our transportation revenue was \$9 million lower due to nonrenewal of expiring contracts, restructuring of certain contracts at lower volumes or discounted rates and lower usage and interruptible revenues due to milder weather. Our EBDA was further burdened by \$8 million of higher pipeline maintenance, contractor costs and property taxes. Partially offsetting these unfavorable EBDA impacts were \$9 million of expansion projects placed in service in 2010;
- WIC's EBDA decreased by \$5 million in 2011 as compared to 2010. Our EBDA was unfavorably impacted by \$9 million largely due to nonrenewal of expiring contracts, higher third party capacity commitments and unfavorable gas balance revaluations. Additionally, our EBDA was lower by \$3 million primarily due to higher contractor costs related to maintenance and equipment repairs. Partially offsetting these unfavorable EBDA impacts were \$8 million of expansion projects placed in service in 2010; and
- SLNG contributed higher EBDA of \$7 million. Our EBDA was favorably impacted by \$11 million due to the completion Elba III Phase A Expansion project in 2010 partially offset by \$4 million of higher contractor costs due to maintenance and repairs.

*Depreciation and Amortization*

After adjusting for the items described in footnote (4) above, our depreciation and amortization expense was \$15 million higher in 2011 as compared to 2010 due to increased property, plant and equipment additions mainly related to expansion projects placed in service during 2011 and 2010.

*General and Administrative Expenses*

After adjusting for the items described in footnote (5) above, general and administrative expenses were \$4 million higher in 2011 as compared to 2010 primarily due to higher benefit costs.

### *Interest and Debt Expense, net*

After adjusting for the items described in footnote (6) above, interest and debt expense, net, increased by \$69 million in 2011 as compared to 2010. The increase was primarily due to higher average debt outstanding used to partially fund acquisitions and expansion projects and lower allowance for debt funds used during construction as a result of expansion projects placed in service during 2010 and 2011. The increase in our average debt outstanding was attributable to the debt issuance of \$500 million by EPPOC in September 2011 and \$300 million by SNG in June 2011. Also contributing to the 2011 increase in interest expense was an increase in interest rates primarily as a result of refinancing our revolving credit facility in May 2011.

### *Net Income Attributable to Noncontrolling Interests*

The decrease in net income attributable to noncontrolling interest for 2011 as compared to 2010 was primarily due to the acquisition of the remaining 49% interest in each of SLNG and Elba Express in November 2010, our acquisition of an additional 28% interest in CIG in June 2011 and our acquisition of the aggregate remaining 40% interest in SNG in March and June 2011.

### *Liquidity and Capital Resources*

#### *General*

Our primary sources of cash include cash flow from operations and funds obtained through long-term financing activities and bank credit facilities. Our primary uses of cash are funding capital expenditure programs, meeting our debt service obligations, meeting operating needs and paying distributions.

As of December 31, 2012, we had approximately \$1.1 billion of liquidity consisting of \$992 million of availability under our revolving credit facility and \$114 million of cash on hand. Our outstanding short-term debt as of December 31, 2012 was \$93 million, consisting of \$88 million in EPPOC senior notes and \$5 million in capital lease obligations. We intend to refinance our short-term debt through a combination of long-term debt and equity or additional bank credit facility borrowings to replace current maturities of long-term debt. We may generate additional sources of cash through future issuances of additional partnership units and/or future debt offerings. For a further discussion of our debt obligations, see Note 6 to our consolidated financial statements included elsewhere in this report.

We expect our current liquidity sources and operating cash flow to be sufficient to fund our estimated 2013 capital program. 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. We will continue to assess and take further actions where prudent to meet our long-term objectives and capital requirements.

#### *Partnership Distributions*

We declared a total cash distribution of \$2.25 per unit for the year ended December 31, 2012. This distribution is 17% higher than the \$1.93 per unit distribution we declared in 2011. Our declared distribution for the year ended December 31, 2012 of \$2.25 per unit will result in an IDR payment to our general partner of \$129 million. Comparatively, our distribution of \$1.93 per unit declared in 2011 resulted in an IDR payment to our general partner in the amount of \$62 million.

#### *Capital Expenditures*

We define sustaining capital expenditures as capital expenditures which do not increase the capacity of an asset. 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, certain of our subsidiaries can each fund their own cash requirements for expansion capital expenditures with proceeds from issuing their own long-term notes or with proceeds from contributions received from their member owners.

All of our capital expenditures, with the exception of sustaining capital expenditures, are classified as discretionary. During 2012 as compared to 2011, our discretionary capital spending decreased by \$73 million primarily due to the completion of Phases II and III of the South System III Expansion project in June 2011 and June 2012, respectively, partially offset by an increase in discretionary capital spending related to Elba Express. Generally, we initially fund our discretionary capital expenditures through borrowings under our credit facility until the amount borrowed is of a sufficient size to cost effectively issue either debt, equity or both.

Our capital expenditures for the year ended December 31, 2012, and the amount we expect to spend for 2013 to sustain and grow our businesses are as follows (in millions):

	<b>2012<sup>(1)</sup></b>	<b>Expected 2013</b>
Sustaining <sup>(2)</sup>	\$ 46	\$ 40
Discretionary	65	158
Total	<u>\$ 111</u>	<u>\$ 198</u>

(1) Includes a net reduction in capital accruals of \$5 million.

(2) Includes our share of Bear Creek and WYCO sustaining capital expenditures.

*Cash Flow*

Our cash flows for the years ended December 31, 2012 and 2011 are summarized as follows (in millions):

	2012	2011
<b>Cash Flow from Operating Activities</b>		
Net income	\$ 589	\$ 605
Non-cash income adjustments	238	206
Change in other assets and liabilities	(111)	7
Total cash flow from operating activities	<u>\$ 716</u>	<u>\$ 818</u>
<b>Cash Inflows</b>		
<i>Investing activities</i>		
Proceeds from sale of assets	\$ 50	\$ 1
Other	2	—
Total cash inflows from investing activities	<u>52</u>	<u>1</u>
<i>Financing activities</i>		
Issuance of debt	1,274	1,771
Net proceeds from issuance of common and general partner units	279	968
Cash contributions to subsidiaries from El Paso	2	34
Total cash inflows from financing activities	<u>1,555</u>	<u>2,773</u>
Total cash inflows	<u>\$ 1,607</u>	<u>\$ 2,774</u>
<b>Cash Outflows</b>		
<i>Investing activities</i>		
Capital expenditures	\$ (116)	\$ (266)
Cash paid to acquire interests in CPG	(185)	—
Other	—	(2)
Total cash outflows from investing activities	<u>(301)</u>	<u>(268)</u>
<i>Financing activities</i>		
Payments of debt, including capital lease obligations	(1,050)	(1,318)
Cash distributions to unitholders and general partner	(564)	(422)
Cash distributions to CPI's preferred interest	—	(14)
Cash distributions by subsidiaries to El Paso	(28)	(116)
Excess of cash paid for CPG interests over contributed book value	(180)	—
Cash paid to acquire additional interests in CIG and SNG	(206)	(1,412)
Other	—	(1)
Total cash outflows from financing activities	<u>\$ (2,028)</u>	<u>\$ (3,283)</u>
Total cash outflows	<u>\$ (2,329)</u>	<u>\$ (3,551)</u>
Net increase (decrease) in Cash and Cash Equivalents	<u>\$ (6)</u>	<u>\$ 41</u>

*Operating Activities.* Our operating cash flow was lower by \$102 million in 2012 as compared to 2011 primarily due to a \$118 million increased use of working capital primarily attributable to the termination of the accounts receivable sales program of \$44 million, reduction of affiliate payables of \$31 million, the CPG interest rate swap settlement of \$12 million and the \$8 million project cancellation payment received in June 2011 as a result of BG LNG exercising their cancellation option on Phase B of SLNG's Elba III Expansion project.

*Investing Activities.* Cash inflows were \$51 million higher in 2012 as compared to 2011 mainly due to the sale of certain SNG non-core offshore assets more fully described in Note 3 to our consolidated financial statements included elsewhere in this report. Cash outflows were \$33 million higher in 2012 as compared to 2011 primarily due to \$185 million paid in 2012 to acquire CPG, partially offset by the impact of \$150 million of lower capital expenditures in 2012 primarily related to lower discretionary capital spending when compared to 2011 due to the completion of Phases II and III of the South System III Expansion project in June 2011 and June 2012, respectively.

*Financing Activities.* During 2012, we borrowed \$805 million from our revolving credit facility, of which \$570 million was used to fund the May 24, 2012 acquisition of CPG and the remaining interest in CIG. We repaid all of the \$805 million revolving credit facility borrowings in 2012 using funds generated from our operations and the majority of the \$469 million net proceeds from the EPPOC debt issuance in November 2012. During 2012, we issued common units and general partner units for net proceeds of \$279 million, which were used to repay \$172 million of CPG debt and \$60 million of EPPOC debt. During 2011, EPPOC and SNG issued debt with aggregate net proceeds of \$789 million and we issued equity of \$968 million primarily used to fund the acquisitions of additional interests in SNG and CIG and the repayment of the 2011 current debt maturities and revolver borrowings. We made cash distributions to our unitholders of \$564 million in 2012 compared with \$422 million in 2011, reflecting a greater number of partnership units outstanding, an increase in our cash distribution per unit and increased incentive distributions to our general partner. In addition, our cash distribution to El Paso decreased by \$88 million in 2012 as compared to 2011 due to our increased ownership interests in SNG and CIG and our acquisition of CPG.

### ***Off-Balance Sheet Arrangements***

We have no significant off-balance sheet financing entities or structures with third parties other than our equity investments in WYCO and Bear Creek. For a further discussion of these off-balance sheet arrangements, see Note 2 to our consolidated financial statements included elsewhere in this report.

### ***Contractual Obligations***

The following table and discussion summarizes our contractual cash obligations as of December 31, 2012 for each of the periods presented (in millions):

<b>Contractual Obligations</b>	<b>Due in Less Than 1 Year</b>	<b>Due in 1-3 Years</b>	<b>Due in 3-5 Years</b>	<b>Thereafter</b>	<b>Total</b>
Long-term financing obligations					
Principal	\$ 93	\$ 831	\$ 574	\$ 2,849	\$ 4,347
Interest	281	531	412	2,316	3,540
Other contractual liabilities	2	1	—	—	3
Operating leases	4	7	4	21	36
Capital commitments	23	—	—	—	23
Transportation and storage	40	61	60	120	281
<b>Total</b>	<b>\$ 443</b>	<b>\$ 1,431</b>	<b>\$ 1,050</b>	<b>\$ 5,306</b>	<b>\$ 8,230</b>

#### *Long-Term Financing Obligations (Principal and Interest)*

Long-term financing obligations represent stated maturities. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rates for fixed rate debt and (ii) current market interest rates and the contractual credit spread for our variable rate debt. Included in these amounts are payments related to the financing obligations of CIG for the construction of WYCO's High Plains pipeline and Totem gas storage facility. CIG makes monthly interest payments on these obligations that are based on 50% of the operating results of High Plains pipeline and Totem storage facility. Also included in these amounts is a compressor station under a capital lease from CIG's unconsolidated investment in WYCO. The compressor station lease expires in November 2029. For a further discussion of our long-term financing and capital lease obligations, see Note 6 to our consolidated financial statements included elsewhere in this report.

#### *Other contractual liabilities*

Included in this amount are environmental liabilities related to sites that we own or have a contractual or legal obligation with a regulatory agency or property owner upon which we perform remediation activities. These liabilities are included in other current and non-current liabilities in our balance sheet.

### *Operating Leases*

For a further discussion of these obligations, see Note 10 to our consolidated financial statements included elsewhere in this report.

### *Capital Commitments*

Included in this amount are capital commitments related to our expansion projects as well as commitments for purchase of plant, property and equipment. We have other planned capital and investment projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures. For a further discussion of these obligations, see Note 10 to our consolidated financial statements included elsewhere in this report.

### *Other Contractual Commitments*

Other contractual commitments are defined as legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations. Included in these commitments are transportation and storage agreements for capacity on third party pipeline systems and storage capacity from an affiliate.

### *Inflation*

We believe that inflation has caused, and may continue to cause, increases in certain operating expenses, and will continue to require higher capital replacement and construction costs. We continually review the adequacy of our rates in relation to such increasing costs of providing services, the inherent regulatory lag experienced in adjusting our rates and the rates we are actually able to charge in our markets.

### *Critical Accounting Estimates*

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

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining: (i) the economic useful lives of our assets; (ii) asset impairment charges; (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. Below are such significant accounting policies.

### *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.

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 10 to our consolidated financial statements included elsewhere in this report.

#### *Legal Matters*

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. For more information on our disclosure of legal matters, see Note 10 to our consolidated financial statements included elsewhere in this report.

#### *Cost-Based Regulation*

We account for our regulated operations in accordance with current Financial Accounting Standards Board accounting standards for rate-regulated operations. The economic effects of regulation can result in a regulated company recording assets for costs that have been or are expected to be approved for recovery from customers or recording liabilities for amounts that are expected to be returned to customers in the rate-setting process in a period different from the period in which the amounts would be recorded by a non-regulated enterprise. Accordingly, we record assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. Management regularly assesses whether regulatory assets are probable of future recovery or if regulatory liabilities are probable of being refunded to our customers by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Based on this continual assessment, management believes the existing regulatory assets are probable of recovery. We periodically evaluate the applicability of accounting standards related to regulated operations, and consider factors such as regulatory changes and the impact of competition. If cost-based regulation ends or competition increases, we may have to reduce certain of our asset balances to reflect a market basis lower than cost and write-off the associated regulatory assets.

#### *Accounting for Other Postretirement Benefits*

We reflect an asset or liability for our subsidiaries' postretirement benefit plan based on its overfunded or underfunded status. As of December 31, 2012, our postretirement benefit plan was overfunded by \$15 million. Our postretirement benefit obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rates used in calculating the benefit obligations. We select our discount rate by matching the timing and amount of our expected future benefit payments for our postretirement benefit obligation to the average yields of various high-quality bonds with corresponding maturities.

Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with the postretirement benefits can be, and often are, revised in the future. The income statement impact of the changes in the assumptions on our related benefit obligations, along with changes to the plan and other items, are deferred and recorded as either accumulated other comprehensive income or a regulatory asset or liability depending on whether these costs are recoverable through rates. A one-percentage point change in the primary assumptions would not have a significant effect on net postretirement benefit cost.

The following table shows the impact of a one percent change to the funded status for the year ended December 31, 2012 (in millions):

	<b>Increase (Decrease) in Funded Status</b>
One percent increase in:	
Discount rates	\$ 6
Health care cost trends	(6)
One percent decrease in:	
Discount rates	(7)
Health care cost trends	5

For more information on postretirement benefits, see Note 7 to our consolidated financial statements included elsewhere in this report.

#### *Asset and Investment Impairments*

The accounting rules on asset and investment impairments require us to continually monitor our businesses, the business environment and the performance of our investments to determine if an event has occurred that indicates that a long-lived asset or investment may be impaired. Such events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. If an event occurs, which is a determination that involves judgment, we evaluate the recoverability of our carrying values based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of the investment in an unconsolidated affiliate. The assessment of project level cash flows requires significant judgment to make projections and assumptions for many years into the future for pricing, demand, competition, operating costs, legal and regulatory issues and other factors that are often outside of our control. Due to the imprecise nature of these projections and assumptions, actual results can, and often do, differ from our estimates. If an impairment is indicated, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying value of the asset downward, if necessary, to its estimated fair value.

**ITEM 7A. *Quantitative and Qualitative Disclosures About Market 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 are required to refinance such debt.

As of December 31, 2012 and 2011, the carrying values of our fixed rate debt were \$4,339 million and \$3,885 million, respectively. These amounts compare to, as of December 31, 2012 and 2011, fair values of \$5,073 million and \$4,284 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. We had no variable rate debt outstanding as of December 31, 2012. The carrying value of our variable rate debt was \$225 million as of December 31, 2011 with a fair value of \$222 million.

For additional information related to our debt obligations, see Note 6 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 [59](#).

**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.

**Changes in Internal Control Over Financial Reporting**

Subsequent to KMI's acquisition of El Paso in May 2012, our internal controls over financial reporting were impacted by changes made to conform our entity-level controls, monitoring activities and disclosure controls and procedures to the existing controls, activities and procedures of KMI. We also converted certain key accounting information systems. There were no other changes in internal controls over financial reporting that have materially affected, or are reasonably likely to affect our internal controls 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***

Set forth below is information concerning the directors and executive officers of El Paso Pipeline GP Company, L.L.C., our general partner. All directors are elected annually by, and may be removed by, KMI, as the ultimate parent of its sole member. All officers of our general partner serve at the discretion of the board of directors of our general partner.

<b>Name</b>	<b>Age</b>	<b>Position with El Paso Pipeline GP Company, L.L.C.</b>
Richard D. Kinder	68	Director, Chairman and Chief Executive Officer
C. Park Shaper	44	Director and President
Steven J. Kean	51	Director, Executive Vice President and Chief Operating Officer
Thomas A. Martin	51	Director and Vice President (President, Natural Gas Pipelines)
Ronald L. Kuehn, Jr.	77	Director
Arthur C. Reichstetter	66	Director
William A. Smith	68	Director
Kimberly A. Dang	43	Vice President and Chief Financial Officer
David D. Kinder	38	Vice President, Corporate Development and Treasurer
Joseph Listengart	44	Vice President, General Counsel and Secretary
James E. Street	56	Vice President, Human Resources and Administration

*Richard D. Kinder* is Director, Chairman and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C., KMI, Kinder Morgan Management, LLC (KMR) and Kinder Morgan G.P., Inc. He was elected Director, Chairman and Chief Executive Officer of El Paso Pipeline GP Company, L.L.C. in May 2012 and KMI in October 1999. 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 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. Mr. Kinder is the uncle of David Kinder, Vice President, Corporate Development and Treasurer of El Paso Pipeline GP Company, L.L.C., KMI, KMR and Kinder Morgan G.P. Inc. Mr. Kinder's experience as Chief Executive Officer of KMI, KMR, Kinder Morgan G.P., Inc. and the general partner of EPB, 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, aligns his economic interests with those of our other stockholders.

*C. Park Shaper* is Director and President of El Paso Pipeline GP Company, L.L.C., KMI, KMR and Kinder Morgan G.P., Inc. Mr. Shaper was elected President of El Paso Pipeline GP Company, L.L.C. in May 2012 and of KMI, Kinder Morgan G.P., Inc. and KMR in May 2005. Mr. Shaper was elected Director of KMR and Kinder Morgan G.P., Inc. in January 2003. He also served as Manager and President 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. 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 our President 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 El Paso Pipeline GP Company, L.L.C., KMI, KMR and Kinder Morgan G.P., Inc. Mr. Kean was elected Executive Vice President and Chief Operating Officer of El Paso Pipeline GP Company, L.L.C. in May 2012 and of KMI, Kinder Morgan G.P., Inc. and KMR in January 2006. He also served as Manager and Chief Operating Officer 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. 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. Mr. Kean's experience as one of our executives since 2002 provides him valuable management and operational expertise and a thorough understanding of our business operations and strategy.

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

*Ronald L. Kuehn, Jr.* is Director of El Paso Pipeline GP Company L.L.C. Mr. Kuehn has been a Director of El Paso Pipeline GP Company L.L.C. since August 2007 and served as Chairman from August 2007 to May 2012. Mr. Kuehn previously served as Chairman of the Board of Directors of El Paso Corporation from March 2003 to May 2009 and Interim Chief Executive Officer from March 2003 to September 2003. From September 2002 to March 2003, Mr. Kuehn served as Lead Director of El Paso. From January 2001 to March 2003, he was a business consultant. Mr. Kuehn served as non-executive Chairman of the Board of El Paso from October 1999 to December 2000. Mr. Kuehn previously served as Chairman of the Board of Sonat Inc. from April 1986 and President and Chief Executive Officer from June 1984 until his retirement in October 1999. Mr. Kuehn formerly served on the Boards of Directors of Praxair, Inc. until 2008, Dun & Bradstreet Corporation until 2007 and Regions Financial Corporation until 2007. His knowledge and understanding of our industry provides the board of our general partner with valuable strategic insight. Mr. Kuehn's prior service on the boards of other publicly-traded companies in our industry, including his service as Chairman of El Paso Corporation and as its interim CEO, provides valuable experience which he can draw upon as a member of the board of our general partner.

*Arthur C. Reichstetter* is Director of El Paso Pipeline GP Company, L.L.C. Mr. Reichstetter has been a Director of El Paso Pipeline GP Company, L.L.C. since November 2007. He has been a private investment manager since 2007. Mr. Reichstetter served as Managing Director of Lazard Freres from April 2002 until his retirement in June 2007. From February 1998 to January 2002, Mr. Reichstetter was a Managing Director with Dresdner Kleinwort Wasserstein, formerly Wasserstein Parella & Co. Mr. Reichstetter was a Managing Director with Merrill Lynch from March 1993 until his retirement in February 1996. Prior to that time, Mr. Reichstetter worked as an investment banker at The First Boston Corporation from 1974 until 1993, in various positions becoming a managing director with that company in 1982. Mr. Reichstetter brings to the board of our general partner extensive experience in investment management and capital markets, as highlighted by his years of service at Lazard Freres, Dresdner Kleinwort Wasserstein and Merrill Lynch. His leadership, together with technical expertise and extensive financial acumen provide the board with the strategic insight and experience necessary to effectuate the growth objectives of the partnership.

*William A. Smith* is Director of El Paso Pipeline GP Company, L.L.C. Mr. Smith has been a Director of El Paso Pipeline GP Company, L.L.C. since May 2008. From 2003 until his retirement as an active partner in 2012, Mr. Smith was a partner in Galway Group, L.P., an investment banking/energy advisory firm headquartered in Houston, Texas. In 2002, Mr. Smith retired from El Paso Corporation, where he was an Executive Vice President and Chairman of El Paso Merchant Energy's Global Gas Group. Mr. Smith had a 29 year career with Sonat Inc. prior to its merger with El Paso in 1999. At the time of the merger, Mr. Smith was Executive Vice President and General Counsel. He previously served as Chairman and President of Southern Natural Gas Company and as Vice Chairman of Sonat Exploration Company. Mr. Smith is currently a director of Eagle Rock Energy G&P LLC, a midstream/upstream master limited partnership and serves as lead director, and as chairman of that company's compensation committee. Mr. Smith previously served on the Board of Directors of Maritrans Inc. until 2006. With over 40 years of experience in the energy industry, Mr. Smith brings to the board of our general partner a wealth of knowledge and understanding of our industry, including valuable legal and business expertise. His experience as an executive and attorney provides the board with an important skill set and perspective. In addition, his experience on the board of directors of other domestic and international energy companies further augments his knowledge and experience.

*Kimberly A. Dang* is Vice President and Chief Financial Officer of El Paso Pipeline GP Company, L.L.C., KMI, KMR, and Kinder Morgan G.P., Inc. Mrs. Dang was elected Chief Financial Officer of El Paso Pipeline GP Company, L.L.C. in May 2012 and of KMI, KMR and Kinder Morgan G.P., Inc. 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 as 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. 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.

*David D. Kinder* is Vice President, Corporate Development and Treasurer of El Paso Pipeline GP Company, L.L.C., KMI, KMR and Kinder Morgan G.P., Inc. Mr. Kinder was elected Treasurer of El Paso Pipeline GP Company, L.L.C. in May 2012 and of KMI, KMR and Kinder Morgan G.P., Inc. in May 2005. He was elected Vice President, Corporate Development of KMI, KMR and Kinder Morgan G.P., Inc. 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. 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 El Paso Pipeline GP Company, L.L.C., KMI, KMR, and Kinder Morgan G.P., Inc. Mr. Listengart was elected Vice President, General Counsel and Secretary of El Paso Pipeline GP Company, L.L.C. in May 2012 and 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. 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.

*James E. Street* is Vice President, Human Resources and Administration of El Paso Pipeline GP Company, L.L.C., KMI, KMR and Kinder Morgan G.P., Inc. He was elected Vice President, Human Resources and Administration of El Paso Pipeline GP Company, L.L.C. in May 2012 and Kinder Morgan G.P., Inc. and KMI in August 1999. Mr. Street was elected Vice President, Human Resources and Administration of KMR upon its formation in February 2001. 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 El Paso Pipeline GP Company, L.L.C., 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 of El Paso Pipeline GP Company, L.L.C., KMR and Kinder Morgan G.P., Inc. effective March 31, 2013. At such time, Steven J. Kean will be elected President and Chief Operating Officer. Mr. Shaper is also retiring as President of KMI, but will remain on the KMI board;
- David D. Kinder will be retiring as Vice President, Corporate Development and Treasurer of El Paso Pipeline GP Company, L.L.C., KMR, Kinder Morgan G.P., Inc. and KMI. At such time, Dax Sanders will be elected Vice President, Corporate Development;
- Joseph Listengart will be retiring as Vice President and General Counsel and Secretary of El Paso Pipeline GP Company, L.L.C., KMR, Kinder Morgan G.P., Inc. and KMI. At such time, David DeVeau will be elected Vice President and General Counsel; and
- David Michels will be elected as Vice President, Investor Relations and Chief Financial Officer of El Paso Pipeline GP Company, L.L.C. and Kimberly Dang will remain as Vice President and Chief Financial Officer of KMR, Kinder Morgan G.P., Inc. and KMI.

Dax A. Sanders, 37, is Vice President Elect, Corporate Development of El Paso Pipeline GP Company, L.L.C., KMR, Kinder Morgan G.P., Inc. and KMI. Mr. Sanders was elected Vice President, Corporate Development 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 El Paso Pipeline GP Company, L.L.C., KMR, Kinder Morgan G.P., Inc. and KMI. Mr. DeVeau was elected Vice President and General Counsel in January 2013, such election to be effective in March 2013. Mr. DeVeau joined Kinder Morgan in 2001 and has served as Deputy General Counsel since 2006. Mr. DeVeau received his Juris Doctor from The Dickinson School of Law, Pennsylvania State University, and a bachelor's degree, cum laude, in political science from Norwich University.

David P. Michels, 34, is Chief Financial Officer Elect of El Paso Pipeline GP Company, L.L.C. and Vice President Elect of Finance and Investor Relations of El Paso Pipeline GP Company, L.L.C., KMR, Kinder Morgan G.P., Inc. and KMI. Mr. Michels was elected Chief Financial Officer and Vice President, Finance and Investor Relations in January 2013, such election to be effective in March 2013. Mr. Michels joined Kinder Morgan in 2012 as Vice President, Finance/Accounting. Prior to joining Kinder Morgan, he spent six years in energy investment banking at Barclays and Lehman Brothers. Mr. Michels holds a master's degree from the University of Chicago Booth School of Business and a bachelor's degree in finance from the University of Texas at Austin.

### ***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. Kuehn, Reichstetter and Smith. Mr. Reichstetter 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 made, within the preceding three years, contributions to any tax-exempt organization in which any of our independent directors serves as an executive officer that in any single fiscal year exceeded the greater of \$1 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 website, at [www.kindermorgan.com](http://www.kindermorgan.com), the governance guidelines, the charter of the audit 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 (Ronald L. Kuehn, Jr.), 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 El Paso Pipeline GP Company, L.L.C., 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, Attention: General Counsel, or by e-mail within the "Contact Us" section of our website, at [www.kindermorgan.com](http://www.kindermorgan.com). Any communication should specify the intended recipient.

### ***Section 16(a) Beneficial Ownership Reporting Compliance***

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

Based solely upon our review of the copies of such forms furnished to us and written representations from executive officers and directors of our general partner, we believe that all such 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, El Paso Pipeline G.P. Company, L.L.C., as our general partner directs, controls and manages all of our activities.

The executive officers of our general partner are also executive officers of KMI, KMR or Kinder Morgan G.P., Inc. The compensation of the executive officers of our general partner is set by the compensation committee of KMI, taking into consideration compensation approved by KMR's compensation committee for such persons also serving as officers of KMR. We have no control over the compensation determination process. The officers of our general partner participate in employee benefit plans and arrangements sponsored by KMI. Other than the Long-Term Incentive Plan described below, neither we nor our general partner has established any employee benefit plans and our general partner has not entered into employment agreements with any of its officers.

### ***Compensation Discussion and Analysis***

We do not directly employ any of the persons responsible for managing or operating our business. Instead, we are managed by our general partner, El Paso Pipeline GP Company, L.L.C., the executive officers of which are employees of KMI. El Paso Pipeline GP Company, L.L.C. operates under an omnibus agreement with El Paso, a wholly-owned subsidiary of KMI, pursuant to which, among other matters:

- KMI makes available to El Paso Pipeline GP Company, L.L.C. the services of the KMI employees who serve as the executive officers of El Paso Pipeline GP Company, L.L.C.; and
- El Paso Pipeline GP Company, L.L.C. is obligated to reimburse KMI for any allocated portion of the costs that it incurs in providing compensation and benefits to such KMI employees.

Although we bear an allocated portion of KMI's costs of providing compensation and benefits to its employees who serve as the executive officers of our general partner, we have no control over such costs and cannot establish or direct the compensation policies or practices of KMI. Each of these executive officers performs services for our general partner, as well as KMI and its affiliates, including KMR, KMP and Kinder Morgan G.P., Inc.

We bore substantially less than a majority of KMI's costs of providing compensation and benefits to the Chief Executive Officer of our general partner (the principal executive officer) and the Chief Financial Officer of our general partner (the principal financial officer) during 2012.

Our general partner has adopted the El Paso Pipeline GP Company, L.L.C. Long-Term Incentive Plan, or *LTIP*, under which equity awards of our partnership may be granted. At this point in time, we do not anticipate that the officers of our general partner (including those that also serve as directors of the general partner) or employees of KMI will receive any grants under the LTIP. As indicated above, the compensation of such officers and employees is made pursuant to KMI's incentive plans and reimbursed by us pursuant to the omnibus agreement. Non-employee directors of our general partner receive equity grants under the LTIP, as described below.

### ***Long-Term Incentive Plan***

The LTIP was designed to promote the interests of our partnership by providing to any employees, consultants, and directors of our general partner and employees and consultants of its affiliates who perform services for us or on our behalf incentive compensation awards for superior performance that are based on our common units. Any employees, directors, and consultants of our general partner or an affiliate who perform services for us and who are selected from time to time by the board of our general partner may be granted awards under the LTIP.

The LTIP is administered by the board of our general partner or a committee thereof. The board of our general partner, subject to the terms of the LTIP, has authority to (i) select the persons to whom awards are to be granted, (ii) determine the size and type of awards, (iii) determine the terms and conditions of any award, including any performance conditions, (iv) determine whether, to what extent, and under what circumstances awards may be settled, exercised, canceled, or forfeited; (v) interpret and administer the LTIP and any instrument or agreement relating to an award made under the LTIP; (vi) establish, amend, suspend, or waive such rules and regulations and appoint such agents as it shall deem appropriate for the proper administration of the LTIP; and (viii) make any other determination and take any other action that the board of our general partner deems necessary or desirable for the administration of the LTIP. All decisions, interpretations and other actions of the board of our general partner are final and binding.

The LTIP authorizes the granting of unit options, restricted common units, phantom units, unit appreciation rights, distribution equivalent rights, other unit-based awards and unit awards. The maximum number of our common units that may at any time be delivered or reserved for delivery under the LTIP is 1,250,000 common units. If any award expires, is canceled, exercised, paid or otherwise terminates without the delivery of common units, then the units covered by such award shall again be units with respect to which awards may be granted.

The board of our general partner may terminate or amend the LTIP at any time with respect to any units for which a grant has not yet been made. The board of our general partner also has the right to alter or amend the LTIP or any part thereof from time to time, including increasing the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially reduce the rights or benefits of the participant without the consent of the participant. The LTIP will expire on the earliest of (i) the date common units are no longer available under the LTIP for grants, (ii) termination of the LTIP by the board of our general partner or (iii) the date 10 years following its date of adoption.

### ***Compensation of Directors***

Officers or employees of KMI or its affiliates who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Directors who are not officers or employees of KMI or its affiliates, referred to in this report as non-employee directors, are compensated for their services on the board, as described below. In addition, each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees thereof. Each director is fully indemnified by us for his or her actions associated with being a director to the fullest extent permitted under Delaware law pursuant to a director indemnification agreement and our partnership agreement.

#### *Cash Retainer*

Each non-employee director of our general partner receives an annual cash retainer paid in quarterly installments. For 2012, the annual cash retainer was \$65,000. In addition, the chairman of the audit committee receives an additional retainer of \$8,000 per year.

#### *Initial Equity Grant*

Each non-employee director, upon joining the board, receives an initial long-term equity grant of restricted common units having a fair value of \$60,000. The restricted common units are granted pursuant to the terms and conditions of the LTIP and vest in three (3) equal installments commencing on the last day of the calendar year of the year in which the grant was made and each of the following two anniversaries thereof. As no non-employee directors joined the board during 2012, no initial equity grants were made in 2012.

#### *Annual Equity Grant*

Each non-employee director who is serving on the board on December 1st receives an annual grant of restricted common units with a value of \$60,000. This annual award is granted pursuant to the terms and conditions of the LTIP and vests in full on the last day of the calendar year following the year in which the grant was made. Annual equity grants for Messrs. Kuehn, Reichstetter and Smith were made on December 1, 2012.

*Director Compensation*

Non-employee directors do not receive stock options or pension benefits. The following table sets forth the aggregate dollar amount of all fees paid to each of the non-employee directors of our general partner during 2012 for their services on the board:

**Director Compensation  
for the Year Ended December 31, 2012**

Name <sup>(1)</sup>	Fees Earned or Paid in Cash <sup>(2)</sup>	Stock Awards <sup>(3)(4)</sup>	All Other Compensation <sup>(5)</sup>	Total
Ronald L. Kuehn, Jr.	\$ 65,000	\$ 60,027	\$ 3,910	\$ 128,937
Arthur C. Reichstetter	73,000	60,027	3,910	136,937
William A. Smith	65,000	60,027	3,910	128,937

- (1) Employee directors do not receive any additional compensation for serving on the board of directors of our general partner; therefore no amounts are shown for the former directors for the period January 1, 2012 until May 24, 2012 or for Messrs. Kinder, Shaper, Kean and Martin for the period from May 25, 2012 until December 31, 2012. Amounts paid as reimbursable business expenses to each director for attending board functions are not reflected in this table. Our general partner does not consider the directors' reimbursable business expenses for attending board functions and other business expenses required to perform board duties to have a personal benefit and thus be considered a perquisite.
- (2) This column reflects the value of a director's annual retainer, as well as the additional retainer for the chairman of the audit committee.
- (3) The amount in this column represents the aggregate grant date fair value of restricted units granted in the fiscal year calculated in accordance with FASB Accounting Standards Codification Topic 718, "Compensation - Stock Compensation." Each of Messrs. Kuehn, Reichstetter and Smith received a grant of 1,608 restricted common units on December 1, 2012 pursuant to the Long-Term Incentive Plan, with each unit having a grant date fair value of \$37.33.
- (4) As of December 31, 2012, each of Messrs. Kuehn, Reichstetter and Smith had 1,608 restricted common units outstanding.
- (5) The amount in this column for Messrs. Kuehn, Reichstetter and Smith represent cash distributions received on unvested restricted common units.

**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 units by all directors of our general partner, by the principal executive officer, principal financial officer and three other most highly compensated executive officers of our general partner (referred to in this report as the named executive officers of our general partner) and by all directors and executive officers as a group; and (ii) the beneficial ownership of our common units 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 El Paso Pipeline Partners L.P., 1001 Louisiana Street, Suite 1000, Houston, Texas 77002.

**Amount and Nature of Beneficial Ownership(a)**

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned <sup>(b)</sup>
Richard D. Kinder	28,000	*
C. Park Shaper	—	*
Steven J. Kean	—	*
Thomas A. Martin	—	*
Ronald L. Kuehn, Jr.	76,668	*
Arthur C. Reichstetter	112,300	*
William A. Smith	12,405	*
Kimberly A. Dang	—	*
Directors and Executive Officers as a group (11 persons)	229,373	*
Kinder Morgan Inc. (c)	90,320,810	41.9%
Tortoise Capital Advisors, L.L.C. (d)	11,622,373	5.4%

\* 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) The percentage of total units to be beneficially owned is based on 215,789,325 common units outstanding as of January 31, 2013.
- (c) Includes 90,320,810 common units held by El Paso, KMI's wholly-owned subsidiary. KMI also indirectly owns our general partner, which holds a 2% general partner interest in us and the incentive distribution rights.
- (d) According to a Schedule 13G/A filed on February 12, 2013, Tortoise Capital Advisors, L.L.C. was deemed to beneficially own 11,622,373 common units. Its address is 11550 Ash Street, Suite 300, Leawood, Kansas 66211.

The following table sets forth information as of January 31, 2013, regarding the beneficial ownership of KMI Class P shares by each of the named executive officers and directors of our general partner and by all directors and executive officers of our general partner as a group.

**Amount and Nature of Beneficial Ownership(a)**

Name of Beneficial owner	KMI Class P Shares	
	Number of Shares	Percent of Class P Shares (b)
Richard D. Kinder <sup>(c)</sup>	240,872,511	23.3%
C. Park Shaper <sup>(d)</sup>	10,663,504	1.0%
Steven J. Kean <sup>(e)</sup>	7,394,843	*
Thomas A. Martin <sup>(f)</sup>	883,824	*
Ronald L. Kuehn, Jr. <sup>(g)</sup>	52,675	*
Arthur C. Reichstetter	—	—
William A. Smith <sup>(h)</sup>	3,622	*
Kimberly A. Dang <sup>(i)</sup>	2,110,498	*
Directors and officers as a group (11 persons) <sup>(j)</sup>	270,247,365	26.1%

\* Less than 1%.

- (a) Except as noted otherwise, each beneficial owner has sole voting power and sole investment power over the shares listed.
- (b) The percentage of total class P shares beneficially owned is based on 1,035,669,044 Class P shares issued and outstanding as of January 31, 2013.
- (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 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.
- (f) 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.
- (g) Includes 10,365 Class P shares owned by Mr. Kuehn's spouse or children. Mr. Kuehn disclaims beneficial ownership of such shares. Amount does not reflect warrants to purchase 79,679 Class P shares held by Mr. Kuehn, which warrants are not currently exercisable based on current market prices for the Class P shares.
- (h) Includes 3,622 Class P shares held by Mr. Smith's wife. Mr. Smith disclaims beneficial ownership of these shares. Amount does not reflect warrants to purchase 5,479 Class P Shares held by Mr. Smith's wife, which warrants are not currently exercisable based on current market prices for the Class P shares. Mr. Smith disclaims beneficial ownership of these warrants.
- (i) 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.
- (j) See notes (c) through (i) above. Also includes 2,450,173 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 TABLE**

The following table provides information concerning securities that may be issued under the El Paso Pipeline GP Company, L.L.C. Long-Term Incentive Plan as of December 31, 2012. For more information regarding this plan, which did not require approval by our limited partners, please read “Executive Compensation - Long-Term Incentive Plan.”

Plan Category	(a)	(b)	(c)
	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by unitholders	\$ —	\$ —	\$ —
Equity compensation plans not approved by unitholders <sup>(1)</sup>	—	—	1,212,291
Total	\$ —	\$ —	\$ 1,212,291

(1) Please read “Executive Compensation — Long-Term Incentive Plan” for a description of the material features of the plan, including the awards that may be granted under the plan.

**ITEM 13. *Certain Relationships and Related Transactions and Director Independence.***

KMI owns 90,320,810 common units, a 41% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us and all of our incentive distribution rights.

***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 9 to our consolidated financial statements included elsewhere in this report.

***Reimbursement of Operating and General and Administrative Expense***

Under the omnibus agreement and other policies, we reimburse KMI and its affiliates without a profit component for the payment of certain operating expenses and for the provision of various operating expenses and general and administrative services for our benefit with respect to the assets contributed to us. The agreements further provide that we reimburse KMI without a profit component for our allocable portion of the premiums on insurance policies covering our assets.

Pursuant to these arrangements, KMI performs centralized corporate functions for us, such as legal, accounting, treasury, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes and engineering. We reimburse KMI and its affiliates without a profit component for our allocable portion of the expenses.

**Contracts with Affiliates**

***Operating and Services Agreements***

On June 30, 1992, CIG entered into a Construction and Operating Agreement with Young Gas Storage Company, Ltd. (Young), a limited partnership in which KMI indirectly owns a general partner interest. This agreement was amended in 1994 and 1997. Under this agreement, CIG agreed to design and construct the Young storage facilities and to operate the facilities (including conducting Young's marketing and administering Young's service agreements) using the same practices that CIG adopts in the operation and administration of its own facilities. CIG is entitled to reimbursement of all costs incurred in the performance of the services, including both direct costs and allocations of general and administrative costs based on direct field labor charges (including any costs charged or allocated to CIG from other affiliates). The agreement is subject to termination only in the event of the dissolution or bankruptcy of CIG, or a material default by CIG that is not cured within certain permissible time periods. Otherwise, the agreement continues until the termination of the Young partnership agreement.

On January 25, 2013, SLNG entered into a Maintenance, Administrative and Operating Agreement with Elba Liquefaction Company, L.L.C., a limited liability company in which Southern Liquefaction Company, LLC is a 51% member. Under the agreement, SLNG agreed to perform operation, maintenance and administrative services associated with the construction and operation of liquefaction facilities at SLNG's Elba Island LNG terminal. SLNG is entitled to reimbursement of all costs incurred in the performance of the services. This agreement is for a primary term of 20 years from the in-service date of the last liquefaction unit to be placed in service pursuant to the underlying service agreement. The agreement can be terminated in the event of default by SLNG that is not cured within certain permissible time periods.

### *Transportation Agreements*

CIG is a party to a capacity release agreement with PSCo, whereby PSCo has released storage capacity in our affiliate, Young, to us for a term expiring on April 30, 2025. PSCo simultaneously contracted for a corresponding quantity of transportation and storage balancing service (which utilizes the storage capacity acquired through the capacity release).

### *Interconnection and Operational Balancing Agreements and Other Inter-Affiliate Agreements*

CIG is a party to interconnection and operational balancing agreements with Ruby Pipeline, L.L.C. (Ruby), of which KMI indirectly owns a 50% equity interest. These agreements require the interconnecting parties to use their respective reasonable efforts to cause the quantities of gas that are tendered/accepted at each point of interconnection to equal the quantities scheduled at those points. The agreements provide for the treatment and resolution of imbalances. The agreements are terminable by either party on 30 days advance notice.

WIC is a party to an "Upstream Pipeline Capacity Agreement" with Ruby. Pursuant to this agreement WIC agreed to offer gas transportation services to shippers desiring to move gas volumes to the inlet of the proposed Ruby pipeline at Opal, Wyoming. Ruby has agreed to reimburse WIC for any unrecovered costs associated with 200 MDth/d of off-system capacity that was acquired by WIC to provide the upstream transportation services (either through a direct payment or through the acquisition of capacity on WIC). The off-system capacity was acquired by WIC on the expansions of the Rockies Express Pipeline from the Piceance Basin to Wamsutter, and the expansion of the Overthrust Pipeline from Wamsutter to Opal.

### *Other Agreements*

In addition, each of WIC, CIG, SLNG, Elba Express, CPG and SNG currently have or will have in the future other routine agreements with KMI and its affiliates that arise in the ordinary course of business, including revised and updated agreements for services and other transportation and exchange agreements and interconnection and balancing agreements with other KMI pipelines.

For a description of certain additional affiliate transactions, see Note 9 to our consolidated financial statements included elsewhere in this report.

### ***Director Independence***

The board has adopted governance guidelines for the board and a charter for the audit committee. The governance guidelines and the rules of the New York Stock Exchange (NYSE) include standards for director independence. As a limited partnership and a "controlled company" (as that term is defined in the rules of the NYSE), we and our general partner are not required to have a majority of independent directors. Copies of the guidelines and the audit committee charter are available on our Internet website at [www.kindermorgan.com](http://www.kindermorgan.com).

The board has affirmatively determined that Ronald L. Kuehn, Jr., Arthur C. Reichstetter and William A. Smith 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-employee directors also meet in executive session without members of management. In January 2013, Mr. Kuehn 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.***

In connection with the KMI's acquisition of El Paso, the audit committee of our general partner approved the engagement of PricewaterhouseCoopers LLP ("PwC") to audit our consolidated financial statements for the year ended December 31, 2012. PwC replaced Ernst & Young ("E&Y"), which was dismissed as our independent auditor effective May 25, 2012. PwC is KMI's and subsidiaries' independent auditor; therefore PwC has become our independent auditor.

The reports of E&Y on our consolidated financial statements for the year ended December 31, 2011 did not contain any adverse opinion or a disclaimer of opinion, and were not qualified or modified as to uncertainty, audit scope or accounting principles.

In connection with the audit of our consolidated financial statements for the year ended December 31, 2011 and reviews for the subsequent interim period through May 24, 2012, there were no disagreements between us and E&Y on any matters of accounting principles or practices, financial statement disclosure, auditing scope or procedures which, if not resolved to the satisfaction of E&Y, would have caused E&Y to make reference to the matter in its reports.

We did not consult with PwC during the year ended December 31, 2011 or any subsequent interim period through May 24, 2012.

	PricewaterhouseCoopers LLP		Ernst & Young	
	2012	2011	2012	2011
Audit fees <sup>(a)</sup>	\$ 2,297,000	\$ —	\$ 480,000	\$ 2,692,000
Tax fees <sup>(b)</sup>	478,000	472,000	235,000	226,000
Audit-related fees	—	—	—	—
All other fees	—	—	—	—
<b>Total</b>	<b>\$ 2,775,000</b>	<b>\$ 472,000</b>	<b>\$ 715,000</b>	<b>\$ 2,918,000</b>

(a) Includes fees for the 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.

(b) Includes fees for professional services rendered for tax processing and preparation of Forms K-1 for our unitholders.

All services rendered by PwC and E&Y are permissible under applicable laws and regulations, and were pre-approved by the audit committee of our general partner. Pursuant to the charter of the audit committee, 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 [64](#).

*(a)(3) Exhibits*

Each exhibit identified below is filed as part of this report. Exhibits filed with this Report are designated by “\*”. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
2.1	Contribution Agreement dated March 24, 2010 by and among El Paso Corporation, El Paso Elba Express Company, L.L.C., Southern LNG Company, L.L.C., El Paso Pipeline Corporation, El Paso Pipeline Holding Company, L.L.C., El Paso Pipeline LP Holdings, L.L.C., El Paso Pipeline GP Company, L.L.C., El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K File No. (001-33825) filed with the SEC on March 25, 2010).
2.2	Contribution Agreement dated June 17, 2010, by and among El Paso Pipeline Partners, L.P., El Paso Corporation, El Paso SNG Holding Company, L.L.C., EPPP SNG GP Holdings, L.L.C., Southern Natural Gas Company, and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K (File No. 001-33825) filed with the SEC on June 22, 2010).
2.3	Contribution Agreement, dated May 17, 2012, by and among El Paso Pipeline Partners, L.P., El Paso Corporation, El Paso LLC, El Paso Noric Investments III, L.L.C., Colorado Interstate Gas Company, L.L.C., El Paso CNG Company, L.L.C., El Paso Cheyenne Holdings, L.L.C., Cheyenne Plains Investment Company, L.L.C., El Paso Pipeline Corporation, El Paso Pipeline Holding Company, L.L.C., El Paso Pipeline GP Company, L.L.C., El Paso Pipeline LP Holdings, L.L.C. and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed with the SEC on May 21, 2012).
3.1	Certificate of Limited Partnership of El Paso Pipeline Partners, L.P. (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1 (File No. 333-145835) filed with the SEC on August 31, 2007).
3.2	First Amended and Restated Agreement of Limited Partnership of El Paso Pipeline Partners, L.P., dated November 21, 2007 (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K filed with the SEC on November 28, 2007); Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of El Paso Pipeline Partners, L.P., dated July 28, 2008 (incorporated by reference to Exhibit 4.A to our Current Report on Form 8-K, filed with the SEC on July 28, 2008).
3.3	Certificate of Formation of El Paso Pipeline GP Company, L.L.C. (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1 (File No. 333-145835) filed with the SEC on August 31, 2007).
3.4	Amended and Restated Limited Liability Company Agreement of El Paso Pipeline GP Company, L.L.C., dated November 21, 2007 (incorporated by reference to Exhibit 3.2 to our Current Report on Form 8-K filed with the SEC on November 28, 2007).

Exhibit Number	Description
4.1	Indenture dated June 1, 1987 between Southern Natural Gas Company and Wilmington Trust Company (as successor to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.A to the Southern Natural Gas Company Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on February 28, 2007); First Supplemental Indenture, dated as of September 30, 1997, between Southern Natural Gas Company and the Trustee (Exhibit 4.A.1 to the Southern Natural Gas Company Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on February 28, 2007); Second Supplemental Indenture dated as of February 13, 2001, between Southern Natural Gas Company and the Trustee (Exhibit 4.A.2 to the Southern Natural Gas Company Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on February 28, 2007); Third Supplemental Indenture dated as of March 26, 2007 between Southern Natural Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on March 28, 2007); Fourth Supplemental Indenture dated as of May 4, 2007 among Southern Natural Gas Company, Wilmington Trust Company (solely with respect to certain portions thereof) and The Bank of New York Trust Company, N.A. (Exhibit 4.C to the Southern Natural Gas Company quarterly report on Form 10-Q for the period ended March 31, 2007, filed with the SEC on May 8, 2007); Fifth Supplemental Indenture dated October 15, 2007 by and among SNG, Wilmington Trust Company, as trustee, and The Bank of New York Trust Company, N.A., as series trustee, to Indenture dated as of June 1, 1987 (Exhibit 4.A to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on October 16, 2007); Sixth Supplemental Indenture dated November 1, 2007 by and among Southern Natural Gas Company, Southern Natural Issuing Corporation, Wilmington Trust Company, as trustee, and The Bank of New York Trust Company, N.A., as series trustee, to Indenture dated as of June 1, 1987 (Exhibit 4.A to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on November 7, 2007); Seventh Supplemental Indenture dated as of June 7, 2011, among the Issuers and Wilmington Trust Company, as trustee (including the form of 4.40% Note due 2021) (incorporated by reference to Exhibit 4.1 to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on June 9, 2011).
4.2	Form of 5.90% Note due 2017 (included as Exhibit A to Exhibit 4.A of the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on March 28, 2007).
4.3	Indenture dated as of March 5, 2003 between Southern Natural Gas Company and The Bank of New York Trust Company, N.A., successor to The Bank of New York, as Trustee (Exhibit 4.C to the Southern Natural Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010).
4.4	Registration Rights Agreement, dated as of June 7, 2011, among the Issuers and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on June 9, 2011).
4.5	Indenture dated as of June 27, 1997, between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A. (successor to Harris Trust and Savings Bank), as trustee (Exhibit 4.A to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010); First Supplemental Indenture dated as of June 27, 1997, between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A.1 to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010); Second Supplemental Indenture dated as of March 9, 2005 between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A.2 to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010); Third Supplemental Indenture dated as of November 1, 2005 between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A.3 to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010); Fourth Supplemental Indenture dated October 15, 2007 by and between Colorado Interstate Gas Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A to the Colorado Interstate Gas Company Current Report on Form 8-K filed with the SEC on October 16, 2007); Fifth Supplemental Indenture dated November 1, 2007 by and among Colorado Interstate Gas Company, Colorado Interstate Issuing Corporation, and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.A to the Colorado Interstate Gas Company Current Report on Form 8-K filed with the SEC on November 7, 2007).
4.6	Indenture, dated March 30, 2010, between El Paso Pipeline Partners Operating Company, L.L.C. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.1 of our Current Report on Form 8-K filed with the SEC on April 5, 2010).
4.7	First Supplemental Indenture, dated March 30, 2010, by and among El Paso Pipeline Partners Operating Company, L.L.C., El Paso Pipeline Partners, L.P. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed with the SEC on April 5, 2010).

Exhibit Number	Description
4.8	Second Supplemental Indenture, dated November 19, 2010, by and among El Paso Pipeline Partners Operating Company, L.L.C., El Paso Pipeline Partners, L.P. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed with the SEC on November 24, 2010).
4.9	Third Supplemental Indenture, dated as of September 20, 2011, by and among El Paso Pipeline Partners Operating Company, L.L.C., El Paso Pipeline Partners, L.P. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.2 of our Current Report on Form 8-K filed with the SEC on September 23, 2011).
4.10	Fourth Supplemental Indenture, dated November 8, 2012, by and among El Paso Pipeline Partners Operating Company, L.L.C., El Paso Pipeline Partners, L.P. and HSBC Bank USA, National Association (incorporated by reference to Exhibit 4.2 to our Current Report on Form 8-K filed with the SEC on November 11, 2012).
10.1	Credit Agreement dated as of May 27, 2011, among El Paso Pipeline Partners Operating Company, L.L.C. and Wyoming Interstate Company, L.L.C., as borrowers, El Paso Pipeline Partners, L.P., as parent guarantor, and the lenders and agents identified therein (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on June 3, 2011).
10.2	Omnibus Agreement, dated November 21, 2007, among El Paso Pipeline Partners, L.P., El Paso Pipeline GP Company, L.L.C., Colorado Interstate Gas Company, Southern Natural Gas Company and El Paso Corporation (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed with the SEC on November 28, 2007).
10.3	Long-Term Incentive Plan of El Paso Pipeline GP Company, L.L.C. (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed with the SEC on November 28, 2007).
10.4	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.20 to our Registration Statement on Form S-1).
10.5	Form of Master Services Agreement by and between Colorado Interstate Gas Company and El Paso Corporation, Tennessee Gas Pipeline Company, El Paso Natural Gas Company and CIG Pipeline Services Company L.L.C. (incorporated by reference to Exhibit 10.21 to our Registration Statement on Form S-1).
10.6	Form of Master Services Agreement by and between Southern Natural Gas Company and El Paso Corporation, Tennessee Gas Pipeline Company and SNG Pipeline Services Company, L.L.C. (incorporated by reference to Exhibit 10.22 to our Registration Statement on Form S-1).
10.7	Note Purchase Agreement, dated September 30, 2008, by and among El Paso Pipeline Partners, L.P., as guarantor, El Paso Pipeline Partners Operating Company, L.L.C., as issuer, and the insurance companies and financial institutions named therein as parties thereto (incorporated by reference to Exhibit 10.M to our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010).
10.8	Lease Agreement dated December 17, 2008, and effective on November 1, 2008, by and between WYCO Development LLC, a Colorado limited liability company, and Colorado Interstate Gas Company, a Delaware corporation (Exhibit 10.C to the Colorado Interstate Gas Company Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 26, 2010).
10.9	Contribution, Conveyance and Assumption Agreement by and among El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C., El Paso Elba Express Company, L.L.C., Southern LNG Company, L.L.C., El Paso Pipeline Corporation, El Paso Pipeline Holding Company, L.L.C., El Paso Pipeline Holdings, L.L.C., El Paso Pipeline GP Company, L.L.C. and El Paso Corporation (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on April 5, 2010).
10.10	Second Amended and Restated Limited Liability Company Agreement of Southern LNG Company, L.L.C. (incorporated by reference to Exhibit 10.4 of our Current Report on Form 8-K filed with the SEC on November 24, 2010).
10.11	Firm Transportation Service Agreement under Rate Schedule FTS, dated October 5, 2007, between Elba Express Company and Shell NA LNG LLC (incorporated by reference to Exhibit 10.A of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, filed with the SEC on May 10, 2010).
10.12	Guaranty dated April 1, 2010, by Shell Oil Company, in favor of Elba Express Company, L.L.C. (incorporated by reference to Exhibit 10.B of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, filed with the SEC on May 10, 2010).

Exhibit Number	Description
10.13	Service Agreement under Rate Schedule LNG-3 dated October 5, 2007, between Southern LNG Inc. and Shell NA LNG LLC (incorporated by reference to Exhibit 10.C of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, filed with the SEC on May 10, 2010).
10.14	Guaranty dated April 1, 2010, by Shell Oil Company, in favor of Southern LNG Company, L.L.C. (incorporated by reference to Exhibit 10.D of our Quarterly Report on Form 10-Q for the period ended March 31, 2010, filed with the SEC on May 10, 2010).
10.15	Contribution Agreement dated November 12, 2010 by and among El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C., El Paso Corporation, El Paso Elba Express Company, L.L.C., Southern LNG Company, L.L.C., Southern Natural Gas Company, El Paso SNG Holding Company, L.L.C. and EPPP SNG GP Holdings, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on November 24, 2010).
10.16	Contribution Agreement dated March 4, 2011 by and among El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C., El Paso Corporation, Southern Natural Gas Company, El Paso SNG Holding Company, L.L.C. and EPPP SNG GP Holdings, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on March 17, 2011).
10.17	Contribution, Conveyance and Assumption Agreement by and among El Paso Pipeline Partners, L.P. El Paso Corporation, El Paso SNG Holding Company, L.L.C., EPPP SNG GP Holdings, L.L.C., Southern Natural Gas Company and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed with the SEC on March 17, 2011).
10.18	Contribution Agreement dated June 29, 2011, by and among El Paso Corporation, El Paso SNG Holding Company, L.L.C., EPPP SNG GP Holdings, L.L.C., Southern Natural Gas Company, El Paso Noric Investments III, L.L.C., Colorado Interstate Gas Company, EPPP CIG GP Holdings, L.L.C., El Paso Pipeline Partners, L.P., and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on July 6, 2011).
10.19	Contribution, Conveyance and Assumption Agreement dated June 29, 2011, by and among El Paso Pipeline Partners, L.P., El Paso Pipeline Partners Operating Company, L.L.C., El Paso SNG Holding Company, L.L.C., EPPP SNG GP Holdings, L.L.C., Southern Natural Gas Company, El Paso Noric Investments III, L.L.C., EPPP CIG GP Holdings, L.L.C., El Paso CNG Company, L.L.C. and El Paso Corporation (incorporated by reference to Exhibit 10.2 of our Current Report on Form 8-K filed with the SEC on July 6, 2011).
10.20	Purchase Agreement, dated as of June 2, 2011, among the Issuers, EPP SNG GP Holdings L.L.C., El Paso SNG Holding Company, L.L.C. and the Initial Purchasers named therein (incorporated by reference to Exhibit 10.1 the Southern Natural Gas Company Current Report on Form 8-K filed with the SEC on June 9, 2011).
10.21	Contribution, Conveyance and Assumption Agreement, dated May 24, 2012, by and among El Paso Pipeline Partners, L.P., El Paso Corporation, El Paso LLC, El Paso Noric Investments III, L.L.C., Colorado Interstate Gas Company, L.L.C., El Paso CNG Company, L.L.C., El Paso Cheyenne Holdings, L.L.C., Cheyenne Plains Investment Company, L.L.C., El Paso Pipeline Corporation, El Paso Pipeline Holding Company, L.L.C., El Paso Pipeline GP Company, L.L.C., El Paso Pipeline LP Holdings, L.L.C. and El Paso Pipeline Partners Operating Company, L.L.C. (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed with the SEC on May 24, 2012).
*12	Ratio of Earnings to Fixed Charges
*21	List of subsidiaries of El Paso Pipeline Partners, L.P.
*23.1	Consent of PricewaterhouseCoopers LLP.
*23.2	Consent of Ernst & Young LLP.
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

<b>Exhibit Number</b>	<b>Description</b>
*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.

	<u>Page Number</u>
<u>Reports of Independent Registered Public Accounting Firms</u>	<u>65</u>
<u>Consolidated Statements of Income for the years ended December 31, 2012, 2011 and 2010</u>	<u>67</u>
<u>Consolidated Statements of Comprehensive Income for the years ended December 31, 2012, 2011 and 2010</u>	<u>68</u>
<u>Consolidated Balance Sheets as of December 31, 2012 and 2011</u>	<u>69</u>
<u>Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010</u>	<u>70</u>
<u>Consolidated Statements of Partners' Capital for the years ended December 31, 2012, 2011 and 2010</u>	<u>72</u>
<u>Notes to Consolidated Financial Statements</u>	<u>74</u>

**Report of Independent Registered Public Accounting Firm**

To the Partners of El Paso Pipeline Partners, L.P.

In our opinion, the accompanying consolidated balance sheet as of December 31, 2012 and the related consolidated statements of income, comprehensive income, partners' capital and cash flows for the year ended December 31, 2012 present fairly, in all material respects, the financial position of El Paso Pipeline Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2012, and the results of their operations and their cash flows for the year then ended 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 under Item 9A. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audit. We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit 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 audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides 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.

/s/ PricewaterhouseCoopers LLP

Houston, Texas  
February 26, 2013

## **Report of Independent Registered Public Accounting Firm**

The Board of Directors of El Paso Pipeline GP Company, L.L.C.  
as General Partner of El Paso Pipeline Partners, L.P.,  
and the Partners of El Paso Pipeline Partners, L.P.:

We have audited the accompanying consolidated balance sheet of El Paso Pipeline Partners, L.P. (the Partnership) as of December 31, 2011, and the related consolidated statements of income, comprehensive income, partners' capital and cash flows for each of the two years in the period ended December 31, 2011. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of El Paso Pipeline Partners, L.P. at December 31, 2011, and the consolidated results of its operations and its cash flows for each of the two years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas  
February 26, 2013

**EI PASO PIPELINE PARTNERS, L.P.**  
**CONSOLIDATED STATEMENTS OF INCOME**  
(In Millions, Except Per Unit Amounts)

	Year Ended December 31,		
	2012	2011 <sup>(1)</sup>	2010 <sup>(1)</sup>
Revenues	\$ 1,515	\$ 1,531	\$ 1,454
Operating Costs and Expenses			
Operation and maintenance	389	419	398
Depreciation and amortization	181	180	165
Taxes, other than income taxes	82	83	72
Total Operating Costs and Expenses	<u>652</u>	<u>682</u>	<u>635</u>
Operating income	<u>863</u>	<u>849</u>	<u>819</u>
Other Income (Expense)			
Earnings from equity investments	14	15	16
Other income, net	5	8	32
Interest and debt expense, net	(293)	(267)	(199)
Total Other Income (Expense)	<u>(274)</u>	<u>(244)</u>	<u>(151)</u>
Income before income taxes	589	605	668
Income tax expense	—	—	2
Net income	<u>589</u>	<u>605</u>	<u>666</u>
Net income attributable to noncontrolling interests	(10)	(93)	(248)
Net income attributable to El Paso Pipeline Partners, L.P.	<u>\$ 579</u>	<u>\$ 512</u>	<u>\$ 418</u>

**Calculation of Limited Partners' Interest in Net Income**

**Attributable to El Paso Pipeline Partners, L.P.:**

Net Income Attributable to El Paso Pipeline Partners, L.P.	\$ 579	\$ 512	\$ 418
Less: Pre-acquisition Earnings Allocated to General Partner	(22)	(40)	(117)
Plus: Severance Costs Allocated to General Partner	34	—	—
Income Subject to 2% Allocation of General Partner Interest	\$ 591	\$ 472	\$ 301
Less: General Partner's Interest	(12)	(9)	(6)
General Partner's Incentive Distribution	(129)	(62)	(14)
Limited Partners' Interest in Net Income	<u>\$ 450</u>	<u>\$ 401</u>	<u>\$ 281</u>
Limited Partners' Net Income per Unit	<u>\$ 2.15</u>	<u>\$ 2.03</u>	<u>\$ 1.90</u>
Weighted Average Number of Units Used in Computation of Limited Partners' Net Income per Unit	<u>209</u>	<u>197</u>	<u>122</u>
Per Unit Cash Distribution Declared	<u>\$ 2.25</u>	<u>\$ 1.93</u>	<u>\$ 1.63</u>
Net Income per Subordinated Unit <sup>(2)</sup>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 1.78</u>

(1) Retrospectively adjusted as discussed in Note 3.

(2) All subordinated units were converted to common units on a one-for-one basis effective January 3, 2011. See Note 8 for computation of Net income attributable to El Paso Pipeline Partners, L.P. per subordinated unit.

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

**EL PASO PIPELINE PARTNERS, L.P.**  
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**  
(In Millions)

	Year Ended December 31,		
	2012	2011 <sup>(1)</sup>	2010 <sup>(1)</sup>
Net income	\$ 589	\$ 605	\$ 666
Other Comprehensive Income:			
Change in fair value of derivatives utilized for hedging purposes	(1)	(6)	(6)
Reclassification of change in fair value of derivatives to net income	4	7	7
Reclassification of terminated hedge to net income <sup>(2)</sup>	12	—	—
Adjustments to postretirement benefit plan liabilities	2	9	—
Total Other Comprehensive Income	<u>17</u>	<u>10</u>	<u>1</u>
Comprehensive income	606	615	667
Comprehensive income attributable to noncontrolling interests	<u>(10)</u>	<u>(94)</u>	<u>(248)</u>
Comprehensive income attributable to El Paso Pipeline Partners, L.P.	<u>\$ 596</u>	<u>\$ 521</u>	<u>\$ 419</u>

(1) Retrospectively adjusted as discussed in Note 3.

(2) See Note 11 for further discussion.

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

**EI PASO PIPELINE PARTNERS, L.P.**  
**CONSOLIDATED BALANCE SHEETS**  
(In Millions, Except Units)

	December 31,	
	2012	2011 <sup>(1)</sup>
<b>ASSETS</b>		
Current assets		
Cash and cash equivalents	\$ 114	\$ 120
Accounts and notes receivable, net	159	101
Inventories	34	32
Assets held for sale	—	50
Regulatory assets	46	24
Other	2	3
Total current assets	<u>355</u>	<u>330</u>
Property, plant and equipment, net	5,931	6,040
Investments	72	71
Regulatory assets	147	153
Other	76	85
Total Assets	<u>\$ 6,581</u>	<u>\$ 6,679</u>
<b>LIABILITIES AND PARTNERS' CAPITAL</b>		
Current liabilities		
Current portion of debt	\$ 93	\$ 82
Accounts payable	72	118
Accrued interest	53	50
Accrued taxes	31	38
Regulatory liabilities	17	15
Contractual deposits	9	17
Accrued other current liabilities	6	25
Total current liabilities	<u>281</u>	<u>345</u>
Long-term liabilities and deferred credits		
Long-term debt	4,246	4,028
Other long-term liabilities and deferred credits	67	75
	<u>4,313</u>	<u>4,103</u>
Total Liabilities	<u>4,594</u>	<u>4,448</u>
Commitments and contingencies (Note 6 and 10)		
Partners' capital		
Common units (215,789,325 and 205,698,750 units issued and outstanding at December 31, 2012 and 2011)	4,253	3,977
General partner units (4,403,765 and 4,197,822 units issued and outstanding at December 31, 2012 and 2011)	(2,276)	(1,855)
Accumulated other comprehensive income (loss)	10	(7)
Total El Paso Pipeline Partners, L.P. partners' capital	<u>1,987</u>	<u>2,115</u>
Noncontrolling interests	—	116
Total Partners' Capital	<u>1,987</u>	<u>2,231</u>
Total Liabilities and Partners' Capital	<u>\$ 6,581</u>	<u>\$ 6,679</u>

(1) Retrospectively adjusted as discussed in Note 3.

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

**EI PASO PIPELINE PARTNERS, L.P.**  
**CONSOLIDATED STATEMENTS OF CASH FLOWS**  
(In Millions)

	Year Ended December 31,		
	2012	2011 <sup>(1)</sup>	2010 <sup>(1)</sup>
<b>Cash Flows From Operating Activities</b>			
Net Income	\$ 589	\$ 605	\$ 666
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	181	180	165
Earnings from equity investments	(14)	(15)	(16)
Distributions from equity investments	13	15	22
Deferred income taxes	—	—	1
Non-cash severance costs	34	—	—
Non-cash asset write down on sale of assets	—	—	21
Other non-cash (income) expense items	24	26	(9)
Changes in components of working capital:			
Accounts receivable	(58)	5	(19)
Regulatory assets	(11)	6	(18)
Other current assets	—	—	4
Accounts payable	(43)	16	(13)
Accrued interest	2	7	14
Accrued taxes	(8)	(3)	(6)
Regulatory liabilities	—	(15)	(15)
Accumulated deferred taxes	—	—	(58)
Other, net	(11)	—	4
Other long-term assets and liabilities	18	(9)	3
<b>Net Cash Provided by Operating Activities</b>	<b>716</b>	<b>818</b>	<b>746</b>
<b>Cash Flows From Investing Activities</b>			
Capital expenditures	(116)	(266)	(411)
Cash paid to acquire interests in CIG, SNG, SLNG, Elba Express and CPG	(185)	—	(1,025)
Proceeds from sale of assets	50	1	1
Distributions from equity investments in excess of cumulative earnings	—	—	16
Net change in notes receivable from affiliates	—	—	322
Other	2	(2)	—
<b>Net Cash Used in Investing Activities</b>	<b>(249)</b>	<b>(267)</b>	<b>(1,097)</b>
<b>Cash Flows from Financing Activities</b>			
Issuance of debt	1,274	1,771	1,448
Payments of debt, including capital lease obligations	(1,050)	(1,318)	(589)
Net proceeds from issuance of common and general partner units	279	968	1,368
Cash distributions to unitholders and general partner	(564)	(422)	(244)
Cash distributions to CPI's preferred interest	—	(14)	(21)
Cash distributions by subsidiaries to El Paso	(28)	(116)	(335)
Cash contributions to subsidiaries from El Paso	2	34	19
Excess of cash paid for CIG, SNG, SLNG, Elba Express and CPG interests over contributed book value	(180)	—	(501)
Cash paid to acquire additional interests in CIG, SNG, SLNG and Elba Express	(206)	(1,412)	(758)
Other	—	(1)	1
<b>Net Cash (Used in) Provided by Financing Activities</b>	<b>(473)</b>	<b>(510)</b>	<b>388</b>
<b>Net increase (decrease) in Cash and Cash Equivalents</b>	<b>(6)</b>	<b>41</b>	<b>37</b>

[Table of Contents](#)

Cash and Cash Equivalents, beginning of period	120	79	42
Cash and Cash Equivalents, end of period	<u>\$ 114</u>	<u>\$ 120</u>	<u>\$ 79</u>
<b>Supplemental Cash Flow Information</b>			
Cash paid during the period for interest (net of capitalized interest)	\$ 274	\$ 274	\$ 173

(1) Retrospectively adjusted as discussed in Note 3.

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

**EI PASO PIPELINE PARTNERS, L.P.**  
**CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL**  
(In Millions)

	Limited Partners		General Partner	Accumulated Other Comprehensive Income (Loss)	Total EPB Partners' Capital	Noncontrolling Interests	Total Partners' Capital
	Common	Subordinated					
Balance at December 31, 2009	\$ 1,305	\$ 297	\$ 227	\$ (16)	\$ 1,813	\$ 1,386	\$ 3,199
Net income	229	52	137	—	418	227	645
Issuance of common and general partner units, net of issuance costs	1,340	—	28	—	1,368	—	1,368
Cash distributions to unitholders and general partner	(188)	(43)	(13)	—	(244)	—	(244)
Cash distributions by subsidiaries to El Paso	—	—	(103)	—	(103)	(232)	(335)
Non-cash contributions from El Paso	—	—	33	—	33	31	64
Cash contributions to subsidiaries from El Paso	—	—	7	—	7	12	19
Cash paid to general partner to acquire interests in SLNG, Elba Express and SNG	—	—	(2,284)	—	(2,284)	—	(2,284)
Acquisition of the remaining interests in SLNG and Elba Express	—	—	443	—	443	(443)	—
Other comprehensive income	—	—	—	1	1	—	1
Other	—	1	—	—	1	—	1
Balance at December 31, 2010	2,686	307	(1,525)	(15)	1,453	981	2,434
Net income	401	—	111	—	512	79	591
Conversion of subordinated units to common units	307	(307)	—	—	—	—	—
Issuance of common and general partner units, net of issuance costs	948	—	20	—	968	—	968
Cash distributions to unitholders and general partner	(365)	—	(57)	—	(422)	—	(422)
Cash distributions by subsidiaries to El Paso	—	—	(37)	—	(37)	(79)	(116)
Cash contributions to subsidiaries from El Paso	—	—	4	—	4	30	34
Cash paid to general partner to acquire interests in CIG and SNG	—	—	(1,412)	—	(1,412)	—	(1,412)
Acquisition of additional interests in CIG and SNG	—	—	896	—	896	(896)	—

[Table of Contents](#)

Third party preferred interest in CPG transferred to El Paso	(1)	—	—	145	—	145	—	145
Other comprehensive income	(1)	—	—	—	8	8	1	9
Balance at December 31, 2011	(1)	3,977	—	(1,855)	(7)	2,115	116	2,231
Net income		450	—	129	—	579	10	589
Issuance of common and general partner units, net of issuance costs		272	—	7	—	279	—	279
Cash distributions to unitholders and general partner		(447)	—	(117)	—	(564)	—	(564)
Cash distributions by subsidiaries to El Paso		—	—	(15)	—	(15)	(13)	(28)
Cash contributions to subsidiaries from El Paso		—	—	—	—	—	2	2
Non-cash contributions from El Paso		—	—	34	—	34	—	34
Cash paid to general partner to acquire interests in CIG and CPG		—	—	(571)	—	(571)	—	(571)
Acquisition of remaining interest in CIG		—	—	114	1	115	(115)	—
Other comprehensive income		—	—	—	16	16	—	16
Other		1	—	(2)	—	(1)	—	(1)
Balance at December 31, 2012		<u>\$ 4,253</u>	<u>\$ —</u>	<u>\$ (2,276)</u>	<u>\$ 10</u>	<u>\$ 1,987</u>	<u>\$ —</u>	<u>\$ 1,987</u>

(1) Retrospectively adjusted as discussed in Note 3.

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

**EI PASO PIPELINE PARTNERS, L.P.**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**1. General**

We are a Delaware master limited partnership (MLP) formed in 2007 to own and operate interstate natural gas transportation and terminaling facilities. When we refer to “us,” “we,” “our,” “ours,” “the company,” or “EPB,” we are describing El Paso Pipeline Partners, L.P. and/or our subsidiaries. We own Wyoming Interstate Company, L.L.C. (WIC), Southern LNG Company, L.L.C. (SLNG), Elba Express Company, L.L.C. (Elba Express), Southern Natural Gas Company, L.L.C. (SNG), Colorado Interstate Gas Company, L.L.C. (CIG) and Cheyenne Plains Investment Company, L.L.C. (CPI), which owns Cheyenne Plains Gas Pipeline Company, L.L.C. (CPG). WIC and CIG are interstate pipeline systems serving the Rocky Mountain region. CPG has an interstate pipeline which serves the Rocky Mountain and Midwest regions. SLNG owns the Elba Island LNG storage and regasification terminal near Savannah, Georgia. Elba Express and SNG are interstate pipeline systems serving the southeastern region of the United States. We are controlled by our general partner, El Paso Pipeline GP Company, L.L.C., a wholly owned subsidiary of El Paso LLC (formerly El Paso Corporation) (El Paso). El Paso became a wholly owned subsidiary of Kinder Morgan, Inc. (KMI) when it was acquired by KMI on May 25, 2012.

**2. Summary of Significant Accounting Policies**

***Basis of Presentation***

We have prepared our accompanying 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 GAAP and referred to in this report as the Codification. 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.

Additionally, our financial statements are consolidated into the consolidated financial statements of KMI; however, our financial statements reflect amounts on a historical cost basis, and, accordingly, do not reflect any purchase accounting adjustments related to KMI's May 25, 2012 acquisition of El Paso. Also, except for the related party transactions described in Note 9, 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.

***Principles of Consolidation***

We consolidate entities when we have the ability to control or direct the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment.

***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. Below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

### ***Cash Equivalents***

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

### ***Accounts Receivable***

The amounts reported as "Accounts and notes receivable, net" on our accompanying Consolidated Balance Sheets at 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 9.

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method. The allowance for doubtful accounts and related provision for bad debt expense was not significant for the years ended December 31, 2012, 2011 and 2010.

### ***Inventories***

Our inventories, which consist of materials and supplies are valued at the lower of cost or market value with cost determined using the average cost method.

### ***Natural Gas Imbalances***

Natural gas imbalances occur when the amount of natural gas delivered from or received by a pipeline system differs from the scheduled amount of gas delivered or received. We value these imbalances due to or from shippers and operators at current index prices. Imbalances are settled in cash or made up in-kind, subject to the terms of the applicable FERC tariff. Imbalances due from others are reported in the Consolidated Balance Sheets as "Accounts and notes, receivable, net." Imbalances owed to others are reported in the Consolidated Balance Sheets as "Accounts payable." We classify all imbalances as current as we expect them to be settled within a year.

### ***Property, Plant and Equipment***

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in service. For constructed assets, we capitalize all construction-related direct labor and material costs, as well as indirect construction costs. Our indirect construction costs primarily include an interest and equity return component (as more fully described below) and labor and related costs of departments associated with supporting construction activities. The indirect capitalized labor and related costs are based upon estimates of time spent supporting construction projects.

We use the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. The FERC-accepted depreciation rate is applied to the total cost of the group until the net book value equals the salvage value. For certain general plant, the asset is depreciated to zero. We re-evaluate depreciation rates each time we redevelop our transportation and storage rates to file with the FERC for an increase or decrease in rates. When property, plant and equipment is retired, accumulated depreciation and amortization is charged for the original cost of the assets in addition to the cost to remove, sell or dispose of the assets, less salvage value. We do not recognize gains or losses unless we sell or retire an entire operating unit, as determined by the FERC. We generally include gains or losses on dispositions of operating units in "Operation and maintenance" expense in our Consolidated Statements of Income. In those instances where we receive recovery in rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount. See Note 3 for information related to a regulatory asset we recorded associated with the sale of certain SNG assets.

Included in our property balances are base gas and working gas at our storage facilities. We periodically evaluate natural gas volumes at our storage facilities for gas losses. When events or circumstances indicate a loss has occurred, we recognize a loss in our income statement or defer the loss as a regulatory asset on our balance sheets if deemed probable of recovery through future rates charged to customers.

We capitalize a carrying cost (an allowance for funds used during construction or AFUDC) on debt and equity funds related to the construction of long-lived assets. This carrying cost consists of a return on the investment financed by debt and a return on the investment financed by equity. The debt portion is calculated based on the average cost of debt. Interest costs capitalized are included as a reduction to "Interest and debt expense, net" on our Consolidated Statements of Income. The equity portion is calculated based on the most recent FERC approved rate of return. Equity amounts capitalized are included in "Other income, net" on our Consolidated Statements of Income.

### ***Asset Retirement Obligations***

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

We are required to operate and maintain our natural gas pipelines, storage systems and LNG facilities, and intend to do so as long as supply and demand for natural gas exists, which we expect for the foreseeable future. Therefore, we believe that we cannot reasonably estimate the asset retirement obligation for the substantial majority of our natural gas pipeline system assets and LNG facility assets because these assets have indeterminate lives.

We continue to evaluate our asset retirement obligations and future developments could impact the amounts we record. Our asset retirement obligations were not significant as of December 31, 2012 and 2011.

### ***Asset and Investment Divestitures/Impairments***

We evaluate our assets and investments for impairment when events or circumstances indicate that their carrying values may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. If an event occurs, which is a determination that involves judgment, we evaluate the recoverability of our carrying values based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of the investment in an unconsolidated affiliate. If an impairment is indicated, or if we decide to sell a long-lived asset or group of assets, we adjust the carrying value of the asset downward, if necessary, to its estimated fair value.

Our fair value estimates are generally based on assumptions market participants would use, including market data obtained through the sales process or an analysis of expected discounted cash flows.

We classify assets (or groups of assets) to be disposed of as held for sale when specific criteria have been met. The lower of the carrying value or the estimated fair value less cost to sell of those assets is considered to determine if recognition of an impairment is required. We cease depreciation and amortization of the assets in the period they are considered held for sale.

### ***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 costs, 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. Our equity method investments include WYCO, which is owned 50% by CIG and Bear Creek, which is owned 50% by SNG.

### ***Revenue Recognition***

Our revenues are primarily generated from natural gas transportation, storage and processing services as well as from LNG storage services and terminal operations and include estimates of amounts earned but unbilled. We estimate these unbilled revenues based on contract data, regulatory information, and preliminary throughput and allocation measurements, among other items. Revenues for all services are based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. For our transportation services and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported or stored. For interruptible or volumetric-based services, we record revenues when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage facility. For contracts with step-up or step-down rate provisions that are not related to changes in levels of service, we recognize reservation revenues ratably over the contract life. Gas not used in operations is based on the volumes we are allowed to retain relative to the amounts of gas we use for operating purposes.

We recognize revenue from gas not used in operations from our shippers when the FERC allows us to retain the volumes at the market prices required under our tariffs. We are subject to FERC regulations and, as a result, revenues we collect may be subject to refund in a rate proceeding. We establish reserves for these potential refunds. We had no reserves for potential refunds at December 31, 2012.

### ***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 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 10.

### ***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 10.

### ***Other Contingencies***

We recognize liabilities for other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other, the low end of the range is accrued.

### ***Postretirement Benefits***

CIG and SNG, our consolidated subsidiaries, maintain a postretirement benefit plan covering certain of their former employees. The plan requires them to make contributions to fund the benefits to be paid out under the plan. These contributions are invested until the benefits are paid out to plan participants. The net benefit cost of the plan is recorded in our Consolidated Statements of Income and is a function of many factors including benefits earned during the year by plan participants (which is a function of factors such as the level of benefits provided under the plan, actuarial assumptions and the passage of time), expected returns on plan assets and amortization of certain deferred gains and losses. For a further discussion of our policies with respect to CIG's and SNG's postretirement benefit plan, see Note 7.

In accounting for CIG's and SNG's postretirement benefit plan, we record an asset or liability based on the overfunded or underfunded status. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded as either a regulatory asset or liability or recorded as "Other comprehensive income (loss)" until those gains or losses are recognized on our Consolidated Statements of Income.

### ***Noncontrolling Interests***

Noncontrolling interests represent the outstanding ownership interests in our consolidated operating limited partnerships that are not owned by us. In our accompanying Consolidated Statements of Income, the noncontrolling interests in our net income are shown as an allocation of our consolidated net income and are presented separately as "Net income attributable to noncontrolling interests." In our accompanying Consolidated Balance Sheets, noncontrolling interests represent the ownership interests in our net assets held by parties other than us and are presented separately as "Noncontrolling interests."

### ***Income Taxes***

We are a partnership for income tax purposes and are not subject to either federal income taxes or generally to state income taxes. Our partners are responsible for income taxes on their allocated share of taxable income which may differ from income for financial statement purposes due to differences in the tax basis and financial reporting basis of assets and liabilities. We are unable to readily determine the net difference in the bases of our assets and liabilities for financial and tax reporting purposes because information regarding each partner's tax attributes in us is not available to us.

### ***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.

### ***Partners' Capital***

We allocate our net income to the capital accounts of our general partner and limited partner unitholders based on the terms of the partnership agreement. The agreement requires these allocations to be made based on the relative percentage of their ownership interests, adjusted for any replenishment of previously allocated aggregate net losses and/or special allocations, each as defined in our partnership agreement. As a result of the retrospective consolidation of CIG, SLNG, Elba Express, SNG and CPG, earnings prior to the acquisitions of the incremental interests in these subsidiaries (pre-acquisition earnings) have been allocated solely to our general partner. See Note 3 for additional information related to the retrospective consolidation of subsidiaries to reflect the reorganization of entities under common control and the change in reporting entity.

Our partnership agreement authorizes us to issue an unlimited number of additional partnership securities on the terms and conditions determined by our general partner without the approval of our unitholders. Accordingly, all of our issued units are authorized and outstanding, and there are an unlimited number of units that are authorized beyond those currently issued.

### ***Regulated Operations***

Our interstate natural gas pipelines, storage operations and LNG receiving terminal are subject to the jurisdiction of the FERC and follow the FASB's accounting standards for regulated operations. Under these standards, we record regulatory assets and liabilities that would not be recorded for non-regulated entities. Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges or credits that are expected to be recovered from or refunded to customers through the rate making process. Items to which we apply regulatory accounting requirements include certain postretirement benefit plan costs, losses on reacquired debt, losses on the sale of certain long lived assets, taxes related to an equity return component on regulated capital projects in periods prior to our subsidiaries' change in legal structure to non taxable entities, certain costs related to gas not used in operations and other costs included in, or expected to be included in, future rates.

### **3. Acquisitions and Divestitures**

#### ***2010 Acquisitions***

In March 2010, we acquired a 51% interest in each of SLNG and Elba Express from El Paso for \$810 million. The consideration paid to El Paso consisted of \$658 million in cash and the issuance of common units and general partner units. We financed the cash payment through (i) net proceeds of \$420 million from the issuance of public debt in March 2010, (ii) \$236 million of cash on hand from the proceeds of our January 2010 public offering of common units and related issuance of general partner units to El Paso and (iii) \$2 million borrowed under our revolving credit facility. We recorded the additional interests in SLNG and Elba Express at their historical cost of \$468 million and the excess cash paid to El Paso of \$190 million over contributed book value as a decrease to general partner's capital. Subsequent to the acquisition, we had the ability to control SLNG's and Elba Express' operating and financial decisions and policies and as a result consolidated SLNG and Elba Express in our financial statements. We retrospectively adjusted our historical financial statements in all periods to reflect the reorganization of entities under common control and the change in reporting entity. We reflected El Paso's 49% interest in each of SLNG and Elba Express as noncontrolling interests in our financial statements until the acquisition of the remaining 49% interest in each of SLNG and Elba Express in November 2010. As a result of the retrospective consolidation, SLNG's and Elba Express' earnings prior to the March 2010 acquisition date were allocated solely to our general partner. The retrospective consolidation of SLNG and Elba Express increased net income attributable to EPB by \$16 million for the year ended December 31, 2010.

In June 2010, we acquired an additional 20% interest in SNG from El Paso for \$493 million in cash. We financed the cash payment through (i) net proceeds of \$325 million from our June 2010 public offering of common units and the related issuance of general partner units to El Paso, (ii) \$110 million from the issuance of public debt, (iii) \$21 million from El Paso's repayment of our demand notes receivable and (iv) \$37 million borrowed under our revolving credit facility. We recorded the additional interest in SNG at its historical cost of \$319 million and the excess cash paid to El Paso of \$174 million over contributed book value as a decrease to "General Partner's Capital."

In November 2010, we acquired the remaining 49% interest in each of SLNG and Elba Express and an additional 15% interest in SNG from El Paso for an aggregate consideration of \$1,133 million in cash. We financed the cash payment through (i) net proceeds of \$415 million from the September 2010 public offering of common units and related issuance of general partner units to El Paso, (ii) net proceeds of \$347 million from the November 2010 public offering of common units and related issuance of general partner units to El Paso (iii) and \$371 million from the proceeds of the November 2010 debt offering. Of the aggregate consideration, \$758 million was related to the acquisition of the remaining 49% interest in each of SLNG and Elba Express. Such transaction was for the acquisition of additional interests in already consolidated entities, and as a result was accounted for on a prospective basis. Accordingly, we decreased our historical noncontrolling interest by \$443 million associated with SLNG and Elba Express and reflected the amount as an increase to "General Partner's Capital."

We recorded the additional interest in SNG at its historical cost of \$238 million and the excess cash paid to El Paso of \$137 million over contributed book value as a decrease to "General Partner's Capital." Subsequent to the SNG acquisition, we had the ability to control SNG's operating and financial decisions and policies and therefore consolidated SNG in our financial statements. We retrospectively adjusted our historical financial statements in all periods to reflect the reorganization of entities under common control and the change in reporting entity. We reflected El Paso's 40% interest in SNG as a noncontrolling interest in our financial statements until the acquisition of incremental interests in March and June 2011. As a result of the retrospective consolidation of SNG, pre-acquisition earnings of the incremental interests in SNG, in historical periods are allocated solely to our general partner. The retrospective consolidation of SNG increased net income attributable to EPB by \$61 million for the year ended December 31, 2010.

### ***2011 Acquisitions***

In March 2011, we acquired an additional 25% interest in SNG from El Paso for \$667 million in cash. We financed the acquisition through (i) net proceeds of \$467 million from our March 2011 public offering of common units and related issuance of general partner units to El Paso and (ii) \$200 million borrowings under our revolving credit facility. This transaction was for the acquisition of an additional interest in an already consolidated entity, thus was accounted for on a prospective basis.

In June 2011, we acquired the remaining 15% interest in SNG and an additional 28% interest in CIG from El Paso for \$745 million in cash. We financed the acquisition through (i) net proceeds of \$501 million from our May 2011 public offering of common units and related issuance of general partner units to El Paso, including the underwriters' June 2011 exercise of the overallotment option and (ii) \$244 million borrowings under our revolving credit facility. This transaction was for the acquisition of additional interests in already consolidated entities, thus was accounted for on a prospective basis.

We have decreased our historical noncontrolling interests in SNG and CIG for both the March and June 2011 acquisitions by \$896 million and reflected that amount as an increase to "General Partner's Capital." We reflected El Paso's interest in SNG and CIG as noncontrolling interest in our financial statements. El Paso's interest in SNG was 40% from January 1, 2011 to March 13, 2011 and 15% until the June 29, 2011 acquisition of the remaining interest. Subsequent to the June 2011 acquisition, SNG became a wholly owned subsidiary of EPB. We reflected El Paso's 42% interest in CIG as noncontrolling interest in our financial statements for the period from January 1, 2011 to June 29, 2011 and 14% until the May 24, 2012 acquisition of the remaining interest.

### ***2012 Acquisitions***

In May 2012, we acquired the remaining 14% interest in CIG and a 100% interest in CPG from El Paso for \$635 million. The consideration paid to El Paso consisted of \$571 million in cash and the issuance of common units. We financed the cash payment through (i) \$570 million in borrowings under our credit facility and (ii) \$1 million from the issuance of general partner units. We recorded our interest in CPG at its historical cost of \$185 million and the excess cash paid over contributed book value of \$180 million as a decrease to general partner's capital. Also decreasing general partner's capital was \$206 million of cash paid to acquire the remaining interest in CIG. Subsequent to the acquisition, we had the ability to control CPG's operating and financial decisions and policies and have consolidated CPG in our financial statements. We have retrospectively adjusted our historical financial statements in all periods presented to reflect the reorganization of entities under common control and the change in reporting entity. As a result of the retrospective consolidation, the pre-acquisition earnings of CPG has been allocated solely to our general partner. The retrospective consolidation of CPG increased net income attributable to El Paso Pipeline Partners, L.P. by \$22 million, \$40 million and \$40 million for 2012, 2011 and 2010, respectively. The acquisition of the remaining interest in CIG was for an additional interest in an already consolidated entity; therefore, it was accounted for prospectively. We have decreased the remaining noncontrolling interest in CIG for the May 2012 acquisition by \$115 million and reflected that amount as an increase to "General Partner's Capital" and "Accumulated other comprehensive income (loss)."

For additional information related to the funding of our acquisitions with debt and equity issuances, see Notes 6 and 8, respectively.

### ***Divestitures***

#### ***Natural Buttes***

In November 2009, CIG sold the Natural Buttes compressor station and gas processing plant to a third party for \$9 million and recorded a gain of approximately \$8 million related to the sale, which was included in our Consolidated Statements of Income as a reduction of "Operation and maintenance" expense. Pursuant to the 2009 FERC order approving the sale of the compressor station and gas processing plant, CIG filed for FERC approval of the proposed accounting entries associated with the sale which utilized a technical obsolescence valuation methodology for determining the portion of the composite accumulated depreciation attributable to the plant. In September 2010, the FERC issued an order that utilized a different depreciation allocation methodology to estimate the net book value of the facilities. Based on the order, CIG recorded a non-cash adjustment in 2010 as an increase to operation and maintenance expense of approximately \$21 million to write down the net property, plant and equipment associated with the sale since it was no longer probable of recovery. In October 2010, CIG filed a request for rehearing and clarification of the FERC order and in October 2011, the FERC denied the request.

*SNG Assets*

In September 2011, SNG entered into an agreement to sell certain offshore and onshore assets (including pipeline, platforms and other related assets located in the Gulf of Mexico and Louisiana) for approximately \$50 million. At December 31, 2011, SNG classified these assets as held for sale at fair value which approximated the sales price. The fair value was based on observable market data which is a Level 2 measurement. At December 31, 2011, SNG deferred the estimated loss of approximately \$38 million as a regulatory asset. On June 21, 2012, the FERC issued an order approving the sale, which occurred on November 1, 2012. The regulatory asset balance of \$36 million at December 31, 2012 represents the difference between the net book value and the \$50 million sales price amortized by a fixed monthly rate, with the final accounting and recovery period dependent upon the outcome of the rate case. We believe it is probable that we will receive an acceptable FERC approval and recover the regulatory asset in future rates.

**4. Income Taxes**

Effective February 4, 2010, SLNG, our wholly owned subsidiary, converted into a limited liability company and is no longer subject to income taxes. Except for the period prior to SLNG's conversion into a limited liability company, we or any of our wholly owned subsidiaries were not subject to income taxes during years 2010 through 2012.

*Components of Income Taxes*

There are no current or deferred federal and state income taxes for the years ended December 31, 2012 or 2011. The components of income taxes for SLNG included in income for the year ended December 31, 2010 were not material.

*Effective Tax Rate Reconciliation*

There are no income taxes included in net income for the years ended December 31, 2012 and 2011. Income taxes included in income for SLNG differ from the amounts computed by applying the statutory federal income tax rate of 35% for the following reasons for the year ended December 31, 2010 (in millions, except for %):

	<u>2010</u>
Income taxes at the statutory federal rate of 35%	\$ 212
Decrease	
Income associated with non-taxable entities	(210)
Income tax expense	<u>\$ 2</u>
Effective tax rate	<u>Less than 1%</u>

## 5. Property, Plant and Equipment

### *Classes of Assets and Depreciation Rates*

As of December 31, 2012 and 2011, our property plant and equipment consisted of the following (in millions, except for %):

	Annual Depreciation Rates	December 31,	
	(%)	2012	2011 <sup>(1)</sup>
Transmission and storage facilities	0.9 - 10.0	\$ 7,779	\$ 7,670
General plant	1.76 - 25.0	67	79
Intangible plant	1.76 - 23.0	128	147
Other		202	222
Accumulated depreciation and amortization <sup>(2)</sup>		(2,321)	(2,207)
		5,855	5,911
Land		24	23
Construction work in progress		52	106
Property, plant and equipment, net		\$ 5,931	\$ 6,040

(1) Retrospectively adjusted as discussed in Note 3.

(2) The composite weighted average depreciation rates for the years ended December 31, 2012, 2011 and 2010 were 2.18%, 2.19% and 2.09% respectively.

### *Capitalized Costs During Construction*

The allowance for debt interest amounts capitalized during the years ended December 31, 2012, 2011 and 2010 was \$1 million, \$2 million and \$11 million, respectively. The allowance for equity amounts capitalized during each of the years ended December 31, 2012, 2011 and 2010 was \$3 million, \$7 million and \$28 million, respectively.

## 6. Debt

We classify our debt based on the contractual maturity dates of the underlying debt instruments. We defer costs associated with debt issuance over the applicable term. These costs are then amortized as interest expense in our Consolidated Statements of Income. The following table summarizes the net carrying value of our outstanding debt (in millions):

	As of December 31,	
	2012	2011 <sup>(1)</sup>
El Paso Pipeline Partners Operating Company, L.L.C.		
Note payable to El Paso, due 2012 <sup>(2)</sup>	\$ —	\$ 10
Senior Notes, due 2012 <sup>(2)</sup>	—	35
Senior Notes, 7.93%, due 2012	—	15
Senior Notes, 8.00%, due 2013	88	88
Senior Notes, 4.10%, due 2015	375	375
Senior Notes, 6.50%, due 2020	535	535
Senior Notes, 5.00%, due 2021	500	500
Senior Notes, 7.50%, due 2040	375	375
Senior Notes, 4.70%, due 2042	475	—
Colorado Interstate Gas Company, L.L.C.		
Senior Notes, 5.95%, due 2015	35	35
Senior Notes, 6.80%, due 2015	340	340
Senior Debentures, 6.85%, due 2037	100	100
Southern LNG Company, L.L.C.		
Senior Notes, 9.50%, due 2014	71	71
Senior Notes, 9.75%, due 2016	64	64
Southern Natural Gas Company, L.L.C.		
Notes, 5.90%, due 2017	500	500
Notes, 4.40%, due 2021	300	300
Notes, 7.35%, due 2031	153	153
Notes, 8.00%, due 2032	258	258
Cheyenne Plains Gas Pipeline, L.L.C.		
Nonrecourse project financing	—	180
Total long-term debt	4,169	3,934
Other financing obligations	178	183
Total long-term debt and other financing obligations	4,347	4,117
Less: Unamortized discount	8	7
Current maturities	93	82
Total long-term debt and other financing obligations, less current maturities	\$ 4,246	\$ 4,028

(1) Retrospectively adjusted as discussed in Note 3.

(2) LIBOR plus 3.9% for 2011.

### ***Maturities of Debt***

The scheduled maturities of our outstanding debt as of December 31, 2012 are summarized as follows (in millions):

<b>Year</b>	<b>Commitment</b>
2013	\$ 93
2014	76
2015	755
2016	69
2017	505
Thereafter	2,849
Total long-term debt and other financing obligations	<u>\$ 4,347</u>

### ***Credit Facilities***

In May 2011, El Paso Pipeline Partners Operating Company, L.L.C. (EPPOC) and WIC entered into an unsecured 5-year credit facility with an initial aggregate borrowing capacity of \$1.0 billion, expandable to \$1.5 billion for certain expansion projects and acquisitions. EPPOC is a wholly owned subsidiary of EPB. In May 2012, we borrowed from our revolving credit facility to fund the acquisition of CPG and the remaining interest in CIG (see Note 3). On May 24, 2012, Standard & Poor's raised our credit rating, triggering a pricing level change. Our interest rate for borrowings under our credit facility has decreased from the London Interbank Offered Rate (LIBOR ) plus 2% to LIBOR plus 1.75% and the commitment fee paid for unutilized commitments decreased from 0.4% to 0.3% and these rates remained effective at December 31, 2012. As of December 31, 2012, we had no outstanding balance under our revolving credit facility and \$8 million outstanding in letters of credit. Our remaining availability under this facility was \$992 million. Borrowings under the credit facility are guaranteed by EPB.

The credit facility contains covenants and provisions that affect us, the borrowers and our other restricted subsidiaries, including, without limitation, customary covenants and provisions:

- prohibiting the borrowers from creating or incurring indebtedness (except for certain specified permitted indebtedness) if such incurrence would cause a breach of the leverage ratio described below;
- limiting our ability and that of the borrowers and our other restricted subsidiaries from creating or incurring certain liens on our respective properties (subject to enumerated exceptions);
- limiting our ability to make distributions and equity repurchases (which shall be permitted if no insolvency default or event of default exists); and
- prohibiting consolidations, mergers and asset transfers by us, the borrowers and our other restricted subsidiaries (subject to enumerated exceptions).

At December 31, 2012, EPPOC was rated investment grade by Fitch (BBB-) and Standard & Poor's (BBB-) and below investment grade by Moody's Investor Services (Ba1).

The credit facility requires that EPB and WIC maintain a consolidated leverage ratio (consolidated indebtedness to consolidated EBITDA) as defined in the credit agreement as of the end of each quarter of less than 5.0 to 1.0 for any trailing four consecutive quarter period; and 5.5 to 1.0 for any such four quarter period during the three full fiscal quarters subsequent to the consummation of specified permitted acquisitions having a value greater than \$25 million. We also have additional flexibility to our covenants for growth projects. In case of a capital construction or expansion project in excess of \$20 million, pro forma adjustments to consolidated EBITDA, approved by the lenders, may be made based on the percentage of capital costs expended and projected cash flows for the project. Such adjustments shall be limited to 25% of actual consolidated EBITDA.

The credit facility contains certain customary events of default that affect us, the borrowers and our other restricted subsidiaries, including, without limitation, (i) nonpayment of principal when due or nonpayment of interest or other amounts within 5 business days of when due; (ii) bankruptcy or insolvency with respect to us, our general partner, the borrowers or any of our other restricted subsidiaries; (iii) judgment defaults against us, our general partner, the borrowers or any of our other restricted subsidiaries in excess of \$50 million; or (iv) the failure of El Paso to directly or indirectly own a majority of the voting equity of our general partner and a failure by us to directly or indirectly own 100% of the equity of EPPOC. As of December 31, 2012 and 2011, we were in compliance with the credit facility covenants.

### ***EPPOC Senior Notes***

EPPOC's senior notes are guaranteed fully and unconditionally by its parent, EPB. EPPOC is a wholly owned subsidiary of EPB. EPB's only operating asset is its investment in EPPOC, and EPPOC's only operating assets are its investments in WIC, CIG, SLNG, Elba Express, SNG and CPG (collectively, the non-guarantor operating companies). EPB's and EPPOC's independent assets and operations, other than those related to these investments and EPPOC's debt are less than 3% of the total assets and operations of EPB, and thus substantially all of the operations and assets exist within these non-guarantor operating companies. Furthermore, there are no significant restrictions on EPPOC's or EPB's ability to access the net assets or cash flows related to its controlling interests in the operating companies either through dividend or loan. The restrictive covenants under these debt obligations are no more restrictive than the restrictive covenants under our credit facility. As of December 31, 2012 and 2011, EPPOC was in compliance with all of its debt related covenants.

In September 2011, EPPOC issued \$500 million of 5.0% senior notes due in 2021. The net proceeds of \$492 million were used to reduce outstanding indebtedness under EPB's revolving credit facility and for general partnership purposes.

In November 2012, EPPOC issued \$475 million of 4.7% senior notes due in 2042. The net proceeds of \$469 million were used to reduce outstanding indebtedness under EPB's revolving credit facility and for general partnership purposes.

### ***CIG Debt***

CIG is subject to a number of restrictions and covenants under its debt obligation. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions. For the year ended December 31, 2012 and 2011, CIG was in compliance with its debt-related covenants.

### ***SLNG Debt***

The SLNG senior notes impose certain limitations on the ability of SLNG to, among other things, incur additional indebtedness, make certain restricted payments, enter into transactions with affiliates, and merge or consolidate with any other person, sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of its assets. SLNG is required to comply with certain financial covenants, including a leverage ratio of no more than 5.0 to 1.0 and an interest coverage ratio of no less than 2.0 to 1.0.

The SLNG senior notes are unsecured and are redeemable at SLNG's option at 100% of the principal amount plus a specified make-whole premium. The SLNG notes are also subject to a change of control prepayment offer in the event of a ratings downgrade within a 120-day period from and including the date on which a change of control with respect to SLNG occurs (as defined in the note purchase agreement). If a sufficient number of the rating agencies downgrade the ratings of the SLNG notes below investment grade within the 120-day period from and including the date of any such change of control, then SLNG is required to offer to prepay the entire unpaid principal amount of the notes held by each holder at 101% of the principal amount of such SLNG notes (without any make-whole amount or other penalty), together with interest accrued thereon to the date for such prepayment. As of December 31, 2012 and 2011, SLNG was in compliance with its debt related covenants.

### ***SNG Debt***

In June 2011, SNG and Southern Natural Issuing Corporation (SNIC), issued \$300 million aggregate principal amount of 4.4% senior unsecured notes due in 2021. The net proceeds of \$297 million from this offering were advanced to EPB under its cash management program and were subsequently utilized to fund SNG growth capital expenditures and for general corporate purposes. The indenture governing these notes contains restrictions and covenants, none of which are more restrictive than those of existing debt covenants.

Under the indentures, SNG is subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens. As of December 31, 2012 and 2011, SNG was in compliance with debt-related covenants.

SNIC is a wholly owned finance subsidiary of SNG and is the co-issuer of certain of SNG's outstanding debt securities. SNIC has no material assets, operations, revenues or cash flows other than those related to its service as a co-issuer of the debt securities. Accordingly, it has no ability to service obligations on the debt securities.

### ***CPG Debt***

In May 2005, CPG entered into a \$266 million nonrecourse project financing agreement with a maturity date of March 31, 2015. At December 31, 2011, CPG had approximately \$180 million outstanding under the agreement, with a variable interest rate of 1.9%. In September 2012, we repaid all borrowings outstanding under the term loan and canceled a related \$12 million letter of credit. See Note 11 for information related to the settlement of the interest rate swaps associated with this loan agreement.

### ***Other Financing Obligations***

In conjunction with the construction of the Totem Gas Storage facility (Totem) and the High Plains pipeline (High Plains), CIG's joint venture partner in WYCO Development L.L.C. (WYCO) funded 50% of the construction costs. We reflected the payments made by their joint venture partner as other long-term liabilities on the balance sheet during construction and, upon project completion, the advances were converted into a financing obligation to WYCO. Upon placing these projects in service, we transferred our title in the projects to WYCO and leased the assets back. Although we transferred the title in these projects to WYCO, the transfer did not qualify for sale leaseback accounting because of our continuing involvement through our equity investment in WYCO. As such, the costs of the facilities remain on our balance sheets and the advanced payments received from our 50% joint venture partner were converted into a financing obligation due to WYCO.

As of December 31, 2012, the principal amounts of the Totem and High Plains financing obligations were \$75 million and \$97 million, respectively, which will be paid in monthly installments through 2039, and extended for the term of related firm service agreements until 2060 and 2043, respectively. The interest rate on these obligations is 15.5%, payable on a monthly basis.

## **7. Retirement Benefits**

### ***Pension and Retirement Savings Plans***

KMI maintains a pension plan and a retirement savings plan covering substantially all of its United States employees, including CIG's and SNG's former employees. The benefits under the pension plan are determined under a cash balance formula. Under its retirement savings plan, KMI contributes an amount equal to 5% of participants' eligible compensation per year. KMI is responsible for benefits accrued under its plans and allocates the related costs to its affiliates.

### ***Postretirement Benefit Plans***

CIG and SNG provide postretirement medical benefits for a closed group of retirees. These benefits may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs and are subject to further benefit changes by KMI, the plan sponsor. In addition, certain former employees continue to receive limited postretirement life insurance benefits. Postretirement benefit plan costs are prefunded to the extent these costs are recoverable through rates. To the extent actual costs differ from the amounts recovered in rates, either "Accumulated other comprehensive income (loss)" or a regulatory asset or liability is recorded. We expect to contribute \$1 million to our postretirement benefit plan in 2013. Contributions of approximately \$1 million were collectively made by CIG and SNG to the postretirement benefit plan for the year ended December 31, 2012, and approximately \$1 million for each of the years ended December 31, 2011 and December 31, 2010.

### ***Accumulated Postretirement Benefit Obligation, Plan Assets and Funded Status***

In accounting for the postretirement benefit plan, we record an asset or liability based on the overfunded or underfunded status. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded as either "Accumulated other comprehensive income (loss)" or a regulatory asset or liability. As part of the rate case settlement as discussed in Note 12, CIG will no longer include these costs in their rates.

The table below provides information about the postretirement benefit plan (in millions):

	December 31,	
	2012	2011
Change in accumulated postretirement benefit obligation:		
Accumulated postretirement benefit obligation — beginning of period	\$ 55	\$ 63
Interest cost	2	3
Participant contributions	1	1
Actuarial loss (gain)	10	(7)
Benefits paid <sup>(1)</sup>	(5)	(5)
Accumulated postretirement benefit obligation — end of period	<u>\$ 63</u>	<u>\$ 55</u>
Change in plan assets:		
Fair value of plan assets — beginning of period	\$ 72	\$ 70
Actual return on plan assets	9	5
Employer contributions	1	1
Participant contributions	1	1
Benefits paid	(5)	(5)
Fair value of plan assets — end of period	<u>\$ 78</u>	<u>\$ 72</u>
Reconciliation of funded status:		
Fair value of plan assets	\$ 78	\$ 72
Less: accumulated postretirement benefit obligation	63	55
Net asset at December 31 <sup>(2)</sup>	<u>\$ 15</u>	<u>\$ 17</u>

- (1) Amounts shown net of a subsidy of less than \$1 million for each of the years ended December 31, 2012 and 2011 related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.
- (2) Net asset amounts are included in "Other" noncurrent assets in our Consolidated Balance Sheets.

*Components of Accumulated Other Comprehensive Income*

The amount recognized in "Accumulated other comprehensive income (loss)" for CIG as of December 31, 2012 and 2011 of \$10 million and \$9 million, respectively, is primarily related to unrecognized gains. We anticipate that approximately \$1 million of "Accumulated other comprehensive income (loss)" will be recognized as part of net periodic benefit income in 2013.

*Plan Assets*

The primary investment objective of the plan is to ensure that, over the long-term life of the plan, an adequate pool of sufficiently liquid assets exists to meet the benefit obligations to retirees and beneficiaries. Investment objectives are long-term in nature covering typical market cycles. Any shortfall of investment performance compared to investment objectives is generally the result of economic and capital market conditions. Although actual allocations vary from time to time from the targeted allocations, the target allocations of the plan's assets are 65% equity and 35% fixed income securities. The plan's assets may be invested in a manner that replicates, to the extent feasible, the Russell 3000 Index and the Barclays Capital Aggregate Bond Index to achieve equity and fixed income diversification, respectively.

We use various methods to determine the fair values of the assets in the postretirement benefit plan, which are impacted by a number of factors, including the availability of observable market data over the contractual term of the underlying assets. We separate the plan's assets into three levels (Level 1, 2 and 3) based on our assessment of the availability of market data and the significance of non-observable data used to determine the fair value of these assets. As of December 31, 2012, assets were comprised of an exchange-traded mutual fund with a fair value of \$4 million and common/collective trust funds with a fair value of \$74 million. As of December 31, 2011, assets were comprised of an exchange-traded mutual fund with a fair value of \$4 million and common/collective trust funds with a fair value of \$68 million. The exchange-traded mutual fund invests primarily in dollar-denominated securities, and its fair value (which is considered a Level 1 measurement) is determined based on the price quoted for the fund in actively traded markets. The common/collective trust funds are invested in approximately 65% equity and 35% fixed income securities, and their fair values (which are considered Level 2 measurements) are determined primarily based on the net asset value reported by the issuer, which is based on similar assets in active markets. Certain restrictions on withdrawals exist for these common/collective trust funds where the issuer reserves the right to temporarily delay withdrawals in certain situations such as market conditions or at the issuer's discretion. The plan does not have any assets that are considered Level 3 measurements. The methods described above may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. There have been no changes in the methodologies used at December 31, 2012 and 2011.

*Expected Payment of Future Benefits*

As of December 31, 2012, we expect the following benefit payments under the plan (in millions):

<u>Year Ending December 31,</u>	<u>Expected Payments<sup>(1)</sup></u>
2013	\$ 5
2014	4
2015	4
2016	4
2017	4
2018 - 2022	20

- (1) Includes a reduction of approximately \$1 million in each of the years 2013 – 2017 and approximately \$5 million in aggregate for 2018 – 2022 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

*Actuarial Assumptions and Sensitivity Analysis*

Accumulated postretirement benefit obligations and net benefit costs are based on actuarial estimates and assumptions. The following table details the weighted average actuarial assumptions used in determining the postretirement plan's obligations and net benefit costs.

	<u>2012</u>	<u>2011</u>	<u>2010</u>
	(%)		
<b>Assumptions related to benefit obligations at December 31:</b>			
Discount rate	3.45	4.43	4.90
<b>Assumptions related to benefit costs for the year ended December 31:</b>			
Discount rate <sup>(1)</sup>	4.25	4.90	5.48
Expected return on plan assets <sup>(2)</sup>	7.50	7.75	7.75

- (1) The discount rates related to benefit costs were 4.42% for the period from January 1, 2012 to May 24, 2012, and 4.12% for the period from May 25, 2012 to December 31, 2012.
- (2) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. We utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on unrelated business income taxes with a weighted average rate of 22% for 2012 and a rate of 35% for 2011 and 2010.

Actuarial estimates for the plan assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 7%, gradually decreasing to 5% by the year 2019. A one-percentage point change would not have a significant effect on interest costs in 2012 and 2011. A one-percentage point change in assumed health care trends would have the following effect as of December 31, 2012 and 2011 (in millions):

	<u>2012</u>	<u>2011</u>
One percentage point increase:		
Accumulated postretirement benefit obligation	\$ 6	\$ 5
One percentage point decrease:		
Accumulated postretirement benefit obligation	\$ (5)	\$ (4)

*Components of Net Benefit Cost (Income)*

For each of the years ended December 31, the components of net benefit cost (income) are as follows (in millions):

	<u>2012</u>	<u>2011</u>	<u>2010</u>
Interest cost	\$ 2	\$ 3	\$ 3
Expected return on plan assets	(5)	(4)	(3)
Net benefit cost (income)	<u>\$ (3)</u>	<u>\$ (1)</u>	<u>\$ —</u>

**8. Partners' Capital**

As of December 31, 2012, 2011 and 2010, our partners' capital included the following limited partner and general partner units:

	<u>December 31, 2012</u>	<u>December 31, 2011</u>	<u>December 31, 2010</u>
<b>Common units:</b>			
Held by third parties	125,468,515	117,298,691	88,767,804
Held by KMI and affiliates	90,320,810	88,400,059	60,672,648
Total limited partner units	215,789,325	205,698,750	149,440,452
General partner units	4,403,765	4,197,822	3,615,578
Total common and general partner units outstanding	220,193,090	209,896,572	153,056,030
<b>Subordinated units:</b>			
Held by El Paso and affiliates	—	—	27,727,411
Total units outstanding	<u>220,193,090</u>	<u>209,896,572</u>	<u>180,783,441</u>

As of December 31, 2012, KMI owns a 41% limited partner interest in us and retains its 2% general partner interest in us and all of our incentive distribution rights (IDRs). The table below provides a reconciliation of our limited and general partner units.

	Unit Reconciliation			
	Limited Partner Units		General Partner	Total Partners' Capital
	Common	Subordinated		
Balance at December 31, 2009	97,622,247	27,727,411	2,558,028	127,907,686
Unit-based compensation to non-employee directors	4,554	—	—	4,554
Acquisition of interests in SLNG and Elba Express	5,346,251	—	109,107	5,455,358
Issuance of units	46,467,400	—	948,443	47,415,843
Balance at December 31, 2010	149,440,452	27,727,411	3,615,578	180,783,441
Unit-based compensation to non-employee directors	5,481	—	—	5,481
Conversion of subordinated units to common units <sup>(1)</sup>	27,727,411	(27,727,411)	—	—
Issuance of units	28,525,406	—	582,244	29,107,650
Balance at December 31, 2011	205,698,750	—	4,197,822	209,896,572
Unit-based compensation to non-employee directors	4,824	—	—	4,824
Issuance of units	8,165,000	—	166,744	8,331,744
Acquisition of interest in CPG and CIG	1,920,751	—	39,199	1,959,950
Balance at December 31, 2012	215,789,325	—	4,403,765	220,193,090

- (1) All subordinated units were converted to common units on a one-for-one basis effective January 3, 2011. See additional discussion below regarding subordinated units.

### ***Equity Issuances***

We issued common units to the public and issued general partner units to KMI and affiliates. The net proceeds from the offerings were used as partial consideration to fund acquisitions from KMI and affiliates and general partnership purposes. The table below shows the units issued, the net proceeds for the issuances (in millions) and the ultimate use of the proceeds.

<u>Issuance Date</u>	<u>Common Units</u>	<u>General Partner Units</u>	<u>Net Proceeds</u>	<u>Use of Proceeds</u>
January 2010	9,862,500	201,404	\$ 236	51% interest in each of SLNG and Elba Express
June 2010	11,500,000	234,694	325	Additional 20% interest in SNG
September 2010	13,225,000	269,898	415	Additional 49% interest in SLNG and Elba Express and additional 15% interest in SNG
November 2010 <sup>(1)</sup>	11,879,900	242,447	392	Additional 49% interest in SLNG and Elba Express and additional 15% interest in SNG
March 2011	13,800,000	281,725	467	Additional 25% interest in SNG
May 2011 <sup>(1)</sup>	14,725,406	300,519	501	Additional 28% interest in CIG and remaining 15% interest in SNG
September 2012 <sup>(1)</sup>	8,165,000	166,744	278	Repayment of CPG debt, certain short-term debt and general partnership purposes

- (1) Includes the underwriters' exercise of the overallotment option.

In addition, in March 2010, we issued 5,346,251 common units and 109,107 general partner units to KMI and affiliates in conjunction with our acquisition of interests in SLNG and Elba Express. Also in May 2012, we issued 1,920,751 common units and 39,199 general partner units to KMI and affiliates in conjunction with our acquisition of CPG and the remainder of CIG. See Note 3 for further discussion.

***Earnings per Unit***

Earnings per unit is calculated based on distributions declared to our unitholders, including distributions related to the IDRs for the related reporting period. To the extent net income attributable to EPB exceeds cash distributions, the excess is allocated to unitholders and the holder of IDRs based on their contractual participation rights to share in those earnings. If cash distributions exceed net income attributable to EPB, the excess distributions are allocated proportionately to all participating units outstanding based on their respective ownership percentages. Additionally, the calculation of earnings per unit does not reflect an allocation of undistributed earnings to the IDR holders beyond amounts distributable under the terms of the partnership agreement. Payments made to our unitholders are determined in relation to actual declared distributions and are not based on the net income allocations used in the calculation of earnings per unit.

As discussed in Note 3, we have retrospectively adjusted our historical financial statements for the consolidations of CIG, SLNG, Elba Express, SNG and CPG following the acquisitions of controlling interest in each entity. As a result of the retrospective consolidations, earnings prior to the acquisition of the incremental interests (pre-acquisition earnings) in these entities have been allocated solely to our general partner in all periods presented.

Net income attributable to EPB per limited partner unit is computed by dividing the limited partners' interest in net income attributable to EPB by the weighted average number of limited partner units outstanding. Diluted earnings per limited partner unit reflects the potential dilution that could occur if securities or other agreements to issue common units were exercised, settled or converted into common units. As of December 31, 2012 and 2011, the dilutive, restricted units outstanding were immaterial.

***Subordinated units***

All of the subordinated units were held by a wholly owned subsidiary of El Paso. Our partnership agreement provided that, during the subordination period, the common units would have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to \$0.2875 per common unit, which is defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus were made on the subordinated units. Furthermore, no arrearages would be paid on the subordinated units. The practical effect of the subordinated units was to increase the likelihood that during the subordination period there would be available cash to be distributed on the common units.

Upon payment of the quarterly cash distribution payment for the fourth quarter of 2010, the financial tests required for the conversion of all subordinated units into common units were satisfied. As a result, all of the subordinated units held by affiliates of El Paso were converted on February 15, 2011 on a one-for-one basis into common units effective January 3, 2011. The conversion did not impact the amount of cash distribution paid or the total number of the Partnership's outstanding units.

The table below shows the net income attributable to El Paso Pipeline Partners, L.P. per common and subordinated unit based on the number of basic and diluted common and subordinated units outstanding for the year ended December 31, 2010 (in millions, except per unit amounts).

	2010	
	Common	Subordinated
Distributions	\$ 214	\$ 45
Undistributed earnings	18	4
Limited partners' interest in net income attributable to El Paso Pipeline Partners, L.P.	<u>\$ 232</u>	<u>\$ 49</u>
Weighted average subordinated units outstanding — Basic and Diluted	122	28
Net income attributable to El Paso Pipeline Partners, L.P. per subordinated unit — Basic and Diluted	\$ 1.90	\$ 1.78

***Incentive Distribution Rights***

Our general partner, as the holder of our IDRs, has the right under our partnership agreement to elect to relinquish the right to receive incentive distribution payments based on the initial cash target distribution levels and (upon satisfaction of certain conditions) to reset, at higher levels, the minimum quarterly distribution amount and cash target distribution levels upon which the incentive distribution payments to our general partner would be set. In connection with this election, our general partner will be entitled to receive a number of newly issued Class B common units and general partner units based on a predetermined formula. In April 2012, the conditions were met which entitled our general partner to reset the minimum quarterly distribution amount and the target distribution levels upon which the incentive distributions payable to our general partner are set. As the reset election has not been made, no Class B units have been issued. For accounting purposes, diluted earnings per unit can be impacted (even if the reset election has not been made) if the combined impact of issuing the Class B units and resetting the cash target distribution is dilutive. Currently, diluted earnings per unit has not been impacted because the combined impact is antidilutive.

Our general partner currently holds all of our IDRs, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement. Based on the quarterly distribution per unit declared for the three months ended December 31, 2012, our general partner received an incentive distribution of \$43 million on February 14, 2013 in accordance with the partnership agreement.

***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 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, who currently owns our IDRs. 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 distributions made to all partners.

Our partnership agreement requires that we distribute all of our available cash from operating surplus each quarter. 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 summarized in the table below. The percentage interests set forth below for our general partner include its 2% general partner interest and assume our general partner has contributed any additional capital necessary to maintain its 2% general partner interest and has not transferred its IDRs.

	<b>Total Quarterly Distribution per Unit Target Amount</b>	<b>Marginal Percentage Interest in Distribution</b>	
		<b>Unitholders</b>	<b>General Partner</b>
Minimum Quarterly Distribution	\$0.2875	98%	2%
First Target Distribution	above \$0.2875 up to \$0.33063	98%	2%
Second Target Distribution	above \$0.33063 up to \$0.35938	85%	15%
Third Target Distribution	above \$0.35938 up to \$0.43125	75%	25%
Thereafter	above \$0.43125	50%	50%

The following table provides information about our distributions (in millions, except per unit distribution amounts):

	Year Ended December 31,		
	2012	2011	2010
Per unit cash distributions declared	\$ 2.25	\$ 1.93	\$ 1.63
Per unit cash distribution paid <sup>(1)</sup>	2.14	1.87	1.55
Cash distributions paid to all partners	564	422	244
General Partner's incentive distribution:			
Declared	129	62	14
Paid <sup>(1)</sup>	105	49	8

- (1) 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.

## 9. Related Party Transactions

### *Cash Distributions*

#### *CIG Cash Distributions to El Paso*

CIG made quarterly distributions to its owners. We have reflected 42% of CIG's distributions paid to El Paso through June 2011 and 14% thereafter as distributions to its noncontrolling interest holder until CIG became a wholly owned subsidiary of EPB subsequent to the May 2012 acquisition (see Note 3).

#### *SLNG and Elba Express Distributions to El Paso*

As a result of the March 2010 acquisition, SLNG and Elba Express were required to make quarterly distributions to its owners of available cash to its members, including us. Since we consolidate SLNG and Elba Express, we have reflected 49% of SLNG's and Elba Express' distributions paid to El Paso as distributions to its noncontrolling interest holder in our financial statements from March 30, 2010 to November 19, 2010. Subsequent to the November 2010 acquisition, as described in Note 3, SLNG and Elba Express became wholly owned subsidiaries of EPB.

#### *SNG Cash Distributions to El Paso*

SNG makes quarterly distributions to its owners. Due to the retrospective consolidation of SNG, the distributions made prior to consolidation in November 2010, excluding distributions paid to its noncontrolling interest holder, were allocated solely to our general partner and were reflected as distributions of pre-acquisition earnings. We have reflected 40% of SNG's distributions paid to El Paso through 2010 and 15% through the first quarter of 2011 as distributions to its noncontrolling interest holder. Subsequent to the June 2011 acquisition as described in Note 3, SNG became a wholly owned subsidiary of EPB.

*CPG Cash Distributions to El Paso*

Due to the retrospective consolidation of CPG, as discussed in Note 3, we have reflected CPG's historical distributions paid to El Paso prior to our consolidation in May 2012 as distributions of pre-acquisition earnings which are allocated solely to our general partner.

The following table summarizes the cash distributions paid to El Paso (in millions):

	Year Ended December 31,		
	2012	2011	2010
<i>CIG Distributions to El Paso</i>			
Distributions to noncontrolling interest holder	\$ 13	\$ 48	\$ 72
<i>SLNG Distributions to El Paso</i>			
Distributions to noncontrolling interest holder	—	—	36
<i>Elba Express Distributions to El Paso</i>			
Distributions to noncontrolling interest holder	—	—	21
<i>SNG Distributions to El Paso</i>			
Distributions to noncontrolling interest holder	—	31	103
Distributions of pre-acquisition earnings	—	—	69
Cash distributions to El Paso	—	31	172
<i>CPG Distributions to El Paso</i>			
Distributions of pre-acquisition earnings <sup>(1)</sup>	15	37	34
Total Cash Distributions to El Paso	<u>\$ 28</u>	<u>\$ 116</u>	<u>\$ 335</u>

(1) Retrospectively adjusted as discussed in Note 3.

**Contributions**

In March 2010, in conjunction with our acquisition of SLNG and Elba Express, El Paso made a non-cash contribution of \$64 million to Elba Express to eliminate its non-interest bearing advance from El Paso. Prior to our 2010 acquisition of a 51% interest in each of SLNG and Elba Express, El Paso made a cash contribution to Elba Express of \$13 million. During 2010, El Paso made capital contributions of \$6 million to SLNG to fund their share of expansion project expenditures for 2010. During 2011, El Paso made capital contributions of \$15 million and \$15 million to CIG and SNG, respectively, to fund their share of expansion project expenditures. In addition, prior to our acquisition of CPG, El Paso made a cash contribution to CPG in 2011 of \$4 million. During 2012, El Paso made a capital contribution of \$2 million to CIG to fund its share of expansion project expenditures.

**Cash Management Program**

Prior to consolidation into EPB, CIG, SLNG and SNG, each participated in El Paso's cash management program, which matched short-term cash surpluses and needs of participating affiliates, thus minimizing total borrowings from outside sources. El Paso used the cash management program to settle intercompany transactions between participating affiliates. After we acquired additional interests in each of these subsidiary companies, which required consolidation, their participation in El Paso's cash management program was terminated. CIG converted its note receivable with El Paso under its cash management program into a demand note receivable. In December 2010, El Paso repaid the demand note. In 2010, SLNG and SNG received \$8 million and \$5 million, respectively, in cash from El Paso in settlement of their note receivable balances related to the termination of their participation in El Paso's cash management program.

**Income Taxes**

Effective February 4, 2010, SLNG converted to a limited liability company and, prior to the conversion, settled its current and deferred tax balances of approximately \$72 million with recoveries of its note receivable from El Paso under the cash management program.

***Affiliate Balances***

We enter into transactions with our affiliates within the ordinary course of business and the services are based on the same terms as non-affiliates, including natural gas transportation services to and from affiliates under long-term contracts and various operating agreements. CIG also contracts with an affiliate to process natural gas and sell extracted natural gas liquids.

We do not have employees. Employees of KMI and its affiliates provide services to our general partner, us and our subsidiaries. We are managed and operated by the directors and officers of our general partner, El Paso Pipeline GP Company, L.L.C., a subsidiary of KMI. Under an omnibus agreement with El Paso and other policies with KMI and its affiliates, we reimburse KMI and its affiliates without a profit component for the provision of various general and administrative services for our benefit and for direct expenses incurred by KMI or its affiliates on our behalf. KMI bills us directly for certain general and administrative costs and allocates a portion of its general and administrative costs without a profit component to us. Prior to KMI's acquisition of El Paso, we were allocated costs from El Paso Natural Gas Company (EPNG) and TGP, our affiliates, associated with our pipeline services. The allocations from TGP, EPNG and El Paso were based on the estimated level of effort devoted to our operations and the relative size of our earnings before interest expense and income taxes, gross property and payroll.

The following table summarizes our balance sheet affiliate balances (in millions):

	December 31,	
	2012	2011 <sup>(1)</sup>
Accounts receivable	\$ 9	\$ 4
Trade payables and net contractual imbalances	13	44
Note payable	—	10
Contractual deposits	—	9
Financing obligations <sup>(2)</sup>	172	177

(1) Retrospectively adjusted as discussed in Note 3.

(2) We have financing obligations payable to WYCO related to Totem and High Plains. See Note 6 for a further discussion of these obligations.

The table below shows overall revenues, expenses and reimbursements from our affiliates for the years ended December 31, 2012, 2011 and 2010 (in millions).

	Year Ended December 31,		
	2012	2011 <sup>(1)</sup>	2010 <sup>(1)</sup>
Revenues	\$ 13	\$ 19	\$ 19
Operating expenses <sup>(2)</sup>	224	242	226
Reimbursement of operating expenses	3	4	6

(1) Retrospectively adjusted as discussed in Note 3.

(2) The 2012 period includes non-cash severance costs of \$34 million allocated to us from El Paso as a result of KMI's acquisition of El Paso, however, we do not have any obligation nor did we pay any amounts related to this expense.

## 10. Litigation, Environmental and Other Contingencies

### *Legal Proceedings*

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

In December 2011 (“*Brinckerhoff I*”) and March 2012, (“*Brinckerhoff II*”) derivative lawsuits were filed in Delaware Chancery Court against El Paso, El Paso Pipeline GP Company, L.L.C., the general partner of EPB, and the directors of the general partner. EPB was named in both lawsuits as a “Nominal Defendant.” The lawsuits arise from the March 2010 and November 2010 drop down transactions involving EPB's purchase of SLNG, Elba Express and SNG. The lawsuits allege various conflicts of interest and that the consideration paid by EPB was excessive. Defendants' motion to dismiss in *Brinckerhoff I* was denied in part. Defendants continue to believe that these actions are without merit and intend to defend against them vigorously.

*Hite Hedge LP, et al. v. El Paso Corporation, et al.*

In December 2011, unitholders of EPB filed a purported class action complaint in Delaware Chancery Court against El Paso and its board members, asserting that the defendants breached their purported fiduciary duties to EPB by entering into the sale agreement with KMI. EPB and EPB's general partner were named in the lawsuit as “Nominal Defendants.” The complaint alleges that the agreement with KMI will result in fewer drop down transactions into EPB and has resulted in a reduction of the price of EPB common units. In February 2012, the defendants filed a motion to dismiss the complaint. The plaintiffs filed an amended complaint adding a derivative claim, and the defendants responded with a second motion to dismiss in April 2012. Defendants' motion to dismiss was granted and the dismissal is now a final judgment.

*Allen v. El Paso Pipeline GP Company, L.L.C., et al.*

In May 2012, a unitholder of EPB filed a purported class action in Delaware Chancery Court, alleging both derivative and non derivative claims, against EPB, and EPB's general partner and its board. EPB was named in the lawsuit as both a “Class Defendant” and a “Derivative Nominal Defendant.” The complaint alleges a breach of the duty of good faith and fair dealing in connection with the March 2011 sale to EPB of a 25% ownership interest in SNG. Defendants' motion to dismiss was denied. Defendants continue to believe this action is without merit and intend to defend against it vigorously.

### *Other Legal Matters*

We and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings and claims that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. For each of these matters, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters cannot be predicted with certainty, and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly, and these adjustments could be material.

As of December 31, 2012 and 2011, we had approximately \$2 million accrued in each period for our outstanding legal proceedings. We do not have any other litigation or claim contingency matters assessed as probable or reasonably possible that would require disclosure in the financial statements.

### *Environmental Matters*

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect of the disposal or release of specified substances at current and former operating sites. At December 31, 2012 and 2011, our accrual was approximately \$3 million and \$10 million for environmental matters. Our accrual includes amounts for expected remediation costs and associated onsite, offsite and groundwater technical studies and related environmental legal costs. At December 31, 2012 and 2011, our accrual includes \$1 million and \$6 million for environmental contingencies related to properties CIG previously owned.

For 2013, we estimate that our total remediation expenditures will be approximately \$1 million, most of which will be expended under government directed clean-up plans. In addition, we expect to make capital expenditures for environmental matters of approximately \$4 million in the aggregate for the years of 2013 through 2017, including capital expenditures associated with the impact of the United States Environmental Protection Agency (EPA) rule on emissions of hazardous air pollutants from reciprocating internal combustion engines which are subject to regulations with which we have to be in compliance by October 2013.

Our recorded environmental liabilities reflect our current estimates of amounts we will expend on remediation projects in various stages of completion. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities.

#### *Superfund Matters*

Included in our recorded environmental liabilities are projects where we have received notice that we have been designated or could be designated, as a Potentially Responsible Party (PRP) under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), commonly known as Superfund, or state equivalents for one active site. Liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. We consider the financial strength of other PRPs in estimating our liabilities.

#### *Clean Air Act Emission Regulation*

On April 17, 2012, the EPA issued regulations pursuant to the federal Clean Air Act to reduce various air pollutants from the oil and natural gas industry. These regulations will limit emissions from certain equipment including compressors, storage vessels and natural gas processing plants. Based on our evaluation of the regulations and its impact on our operations and our financial results, we do not anticipate a material impact on our operations or financial results.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

#### ***Other Commitments***

##### *Capital Commitments*

At December 31, 2012, we have capital commitments of approximately \$4 million related to Southeast Supply Header (SESH), all of which will be spent in 2013. During 2009, we entered into an approximately \$57 million letter of credit associated with our estimated construction costs related to our SESH Expansion project. As invoices are paid under the contract, we are able to reduce the value of the letter of credit. At December 31, 2012, the letter of credit has been reduced to approximately \$8 million. We also have commitments for the purchase of plant, property and equipment of \$19 million, which we expect to spend during 2013. We have other planned capital and investment projects that are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures.

##### *Other Commercial Commitments*

We hold cancelable easement or rights-of-way arrangements from landowners permitting the use of land for the construction and operation of our pipeline systems. Currently, our obligations under these easements are not material to the results of our operations.

##### *Transportation and Storage Commitments*

We have entered into transportation commitments and storage capacity contracts totaling \$281 million at December 31, 2012, of which \$86 million and \$8 million are related to storage capacity contracts with our affiliates, Young Gas Storage Company, Ltd. and Bear Creek, respectively. Our annual commitments under these agreements are \$40 million in 2013, \$31 million in 2014, \$30 million in 2015, \$30 million in 2016, \$30 million in 2017 and \$120 million in total thereafter.

*Operating Leases*

We lease property, facilities and equipment under various operating leases. Our minimum future annual rental commitments under our operating leases at December 31, 2012, are as follows (in millions):

<u>Year Ending December 31,</u>	
2013	\$ 4
2014	4
2015	3
2016	2
2017	2
Thereafter	21
<b>Total minimum lease payments</b>	<b>\$ 36</b>

Rental expense on our operating leases for each of the three years ended December 31, 2012, 2011 and 2010 was \$6 million and is reflected in "Operation and maintenance" expense on our Consolidated Statements of Income. These amounts include our share of rent allocated to us from KMI.

**11. Fair Value**

The following table reflects the carrying amount and estimated fair values of our financial instruments (in millions):

	<u>As of December 31,</u>			
	<u>2012</u>		<u>2011</u>	
	<u>Carrying Amount</u>	<u>Fair Value</u>	<u>Carrying Amount</u>	<u>Fair Value</u>
Long-term debt and other financing obligations, including current maturities	\$ 4,339	\$ 5,073	\$ 4,110	\$ 4,506

(1) Retrospectively adjusted as discussed in Note 3.

As of December 31, 2012 and 2011, the carrying amounts of cash and cash equivalents, short-term borrowings and current receivables and payables represent fair value because of the short-term nature of these instruments.

At December 31, 2012 our financial instruments measured at fair value consisted of our long-term debt and other financing obligations. At December 31, 2011 our financial instruments measured at fair value consisted of interest rate swaps and our long-term debt and other financing obligations. We separate the fair values of our financial instruments into levels based on our assessment of the availability of observable market data and the significance of non-observable data used to determine the estimated fair value. We estimated the fair values of our interest rate derivatives and long-term debt and other financing obligations primarily based on quoted market prices for the same or similar issues, a Level 2 fair value measurement. Our assessment and classification of an instrument within a level can change over time based on the maturity or liquidity of the instrument and this change would be reflected at the end of the period in which the change occurs. During the years ended December 31, 2012 and 2011, there were no changes to the inputs and valuation techniques used to measure fair value, the types of instruments or the levels in which they were classified.

***Interest Rate Derivatives***

In May 2005, CPG entered into two interest rate swap agreements, which were designated as cash flow hedges and effectively converted 80% of the \$266 million term loan from a floating interest rate to a fixed interest rate. At December 31, 2011, these interest rate swaps effectively converted the interest rate on approximately \$144 million of the debt from a floating rate to a fixed rate. The fair value of our interest rate derivatives designated as cash flow hedges were \$14 million at December 31, 2011 and were classified as other liabilities in our accompanying Consolidated Balance Sheets. In September 2012, in conjunction with the repayment of the CPG term loan, we settled the outstanding balance of our accrued liabilities related to our interest rate swaps of approximately \$12 million. There was no ineffectiveness recognized for these interest rate swaps during the periods ended December 31, 2012, 2011 and 2010. The \$12 million loss on termination of these interest rate derivatives included in "Accumulated other comprehensive income (loss)" was deferred as a regulatory asset pursuant to the accounting requirements for regulated operations. The regulatory asset will be amortized over the term of the original debt issuance.

## 12. Regulatory Assets and Liabilities

Our regulatory asset and liability balances are recoverable or reimbursable over various periods. Below are the details of our regulatory assets and liabilities as of December 31 (in millions):

	2012	2011	(1)
<b>Current regulatory assets</b>			
Differences between gas retained and gas consumed in operations	\$ 27	\$ 11	
Unamortized loss on sale of assets	13	6	
Other	6	7	
<b>Total current regulatory assets</b>	<b>46</b>	<b>24</b>	
<b>Non-current regulatory assets</b>			
Taxes on capitalized funds used during construction	78	81	
Unamortized loss on reacquired debt	41	35	
Unamortized loss on sale of assets	23	32	
Other	5	5	
<b>Total non-current regulatory assets</b>	<b>147</b>	<b>153</b>	
<b>Total regulatory assets</b>	<b>\$ 193</b>	<b>\$ 177</b>	
<b>Current regulatory liabilities</b>			
Differences between gas retained and gas consumed in operations	\$ 9	\$ 10	
Other	8	5	
<b>Total current regulatory liabilities</b>	<b>17</b>	<b>15</b>	
<b>Non-current regulatory liabilities</b>			
Property and plant retirements	8	12	
Postretirement benefits	12	18	
Other	13	7	
<b>Total non-current regulatory liabilities</b>	<b>33</b>	<b>37</b>	
<b>Total regulatory liabilities</b>	<b>\$ 50</b>	<b>\$ 52</b>	

(1) Retrospectively adjusted as discussed in Note 3.

Substantially all of our regulatory assets as of December 31, 2012 are being recovered as cost of service in our rates. These assets are expected to be recovered in rates over a period of approximately one year to forty-three years.

Our significant regulatory assets and liabilities include:

*Difference between gas retained and gas consumed in operations*

These amounts reflect the value of volumetric differences between gas retained and consumed in our operations. These amounts are not included in the rate base, but given our tariffs, are expected to be recovered from our customers or returned to our customers in subsequent fuel filing periods.

*Taxes on capitalized funds used during construction*

These regulatory asset balances were established to offset the deferred tax for the equity component of the allowance for funds used during the construction of long-lived assets. Taxes on capitalized funds used during construction and the offsetting deferred income taxes are included in the rate base and are recovered over the depreciable lives of the long lived asset to which they relate. These balances were established on our pipelines prior to their conversion to non-taxable entities.

*Unamortized loss on reacquired debt*

Amount represents the deferred and unamortized portion of losses on reacquired debt which are recovered through the cost of service over the original life of the debt issue, or in the case of refinanced debt, over the life of the new debt issue.

*Unamortized loss on sale of assets*

Amount represents the deferred and unamortized portion of losses on our sale of offshore assets. The recovery is expected to occur at a fixed monthly rate until SNG's next rate case, with the final recovery period dependent upon the outcome of the rate case.

*Postretirement benefits*

Represents unrecognized gains or losses related to SNG's postretirement benefit plan. It also includes the differences between postretirement benefit amounts expensed and the amounts previously recovered in rates for CIG prior to their rate case settlement in September 2011. Prior to CIG's rate case settlement, the balances also included unrecognized gains and losses or changes in actuarial assumptions related to its postretirement benefit plan. As part of the CIG rate case settlement, CIG no longer includes these costs in its rates and during 2011 reclassified approximately \$9 million to "Accumulated other comprehensive income (loss)."

*Property and plant retirements*

Amount represents the deferral of customer-funded amounts for costs of future asset retirements.

**13. Transactions with Major Customers**

Our non-affiliate trade accounts receivable as of December 31, 2012 and 2011 were \$150 million and \$51 million, respectively. We had no other non-affiliate accounts receivable as of December 31, 2012 and \$46 million as of December 31, 2011. Our affiliate receivables are discussed in Note 9.

The following table shows customers with revenues greater than 10% of our operating revenues, which we refer to as major customers, for each of the three years ended December 31 (in millions):

	2012	2011	2010
Shell Oil Company and subsidiaries	\$ 220	\$ 221	\$ 186
PSCo and subsidiary	169	170	169
AGL Resources and subsidiaries	161	163	165

(1) Retrospectively adjusted as discussed in Note 3.

At December 31, 2012, we have transportation and storage agreements with PSCo for capacity on High Plains through 2029 and Totem through 2040 each with annual firm revenue of \$39 million.

**14. Accounts Receivable Sales Program**

We participated in accounts receivable sales programs where we sold receivables in their entirety to a third party financial institution (through wholly-owned special purpose entities). On June 20, 2012, we terminated the accounts receivable sales programs and paid \$44 million to the third-party financial institution, which consisted of sales proceeds received up front and servicing fees. The sale of these accounts receivable (which were short-term assets that generally settled within 60 days) qualified for sale accounting. The third party financial institution involved in these accounts receivable sales programs acquired interests in various financial assets and issued commercial paper to fund those acquisitions. We did not consolidate the third party financial institution because we did not have the power to control, direct or exert significant influence over its overall activities since our receivables did not comprise a significant portion of its operations.

In connection with our accounts receivable sales, we received a portion of the sales proceeds up front and received an additional amount upon the collection of the underlying receivables (which we referred to as a deferred purchase price). Our ability to recover the deferred purchase price was based solely on the collection of the underlying receivables. The table below contains information related to our accounts receivable sales programs (in millions).

	Year Ended December 31,	
	2012	2011
Accounts receivable sold to the third-party financial institution <sup>(1)</sup>	\$ 418	\$ 1,017
Cash received for accounts receivable sold under the program	242	593
Deferred purchase price related to accounts receivable sold	176	424
Cash received related to the deferred purchase price	191	420

(1) During the period ended December 31, 2012, 2011 and 2010, losses recognized on the sale of accounts receivable were immaterial.

	December 31,
	2011
Accounts receivable sold and held by third-party financial institution	\$ 96
Uncollected deferred purchase price related to accounts receivable sold <sup>(2)(3)</sup>	45

- (2) Initially recorded at an amount which approximated its fair value using observable inputs other than quoted prices in active markets, a Level 2 fair value measurement.
- (3) There were no balances outstanding as of December 31, 2012 since all balances were settled in June 2012 when the accounts receivable sales programs were terminated.

The deferred purchase price related to the accounts receivable sold was reflected as "Accounts and notes receivable, net" on our Consolidated Balance Sheets. Because the cash received up front and the deferred purchase price related to the sale or ultimate collection of the underlying receivables, and were not subject to significant other risks given their short term nature, we reflected all cash flows under the accounts receivable sales programs as "Cash Provided by Operating Activities" on our Statements of Cash Flows. Under the accounts receivable sales programs, we serviced the underlying receivables for a fee. The fair value of these servicing agreements, as well as the fees earned, were not material to our financial statements for the years ended December 31, 2012, 2011 and 2010.

## 15. Regulatory Matters

### *WIC*

In November 2012, the FERC notified WIC that it was beginning a rate proceeding under Section 5 of the Natural Gas Act. We are aggressively defending the current rates, which we believe are just and reasonable. Any outcome from this FERC action is not anticipated to have a substantial impact on the overall earnings of EPB. A hearing on this matter is expected with the FERC in the third quarter of 2013.

### *SNG*

On January 31, 2013, the FERC approved SNG's request to amend its January 2010 settlement. The amendment extended the required filing date for SNG's rate case from February 28, 2013 to no later than May 31, 2013. If SNG files a settlement before May 31, 2013, it would not be required to file a rate case and the new rates would be effective as of September 1, 2013. However, if SNG files a rate case on May 31, 2013, the new rates would likely become effective as of December 1, 2013.

### Supplemental Selected Quarterly Financial Information (Unaudited)

Our financial information by quarter is summarized below. Due to the seasonal nature of our business, information for interim periods may not be indicative of our results of operations for the entire year.

	Quarters Ended				Year to Date
	March 31	June 30	September 30	December 31	
(In Millions, Except Per Units Amounts)					
<b>2012</b>					
Revenues	\$ 390	\$ 367	\$ 368	\$ 390	\$ 1,515
Operating income	222	173	220	248	863
Earnings from equity investments	3	4	4	3	14
Net income	155	105	151	178	589
Net income attributable to noncontrolling interests	(6)	(4)	—	—	(10)
Net income attributable to El Paso Pipeline Partners, L.P.	149	101	151	178	579
Limited Partners' Net Income per Unit	0.54	0.44	0.55	0.62	2.15
<b>2011<sup>(1)</sup></b>					
Revenues	\$ 394	\$ 383	\$ 366	\$ 388	\$ 1,531
Operating income	232	211	195	211	849
Earnings from equity investments	4	4	4	3	15
Net income	176	153	131	145	605
Net income attributable to noncontrolling interests	(53)	(27)	(7)	(6)	(93)
Net income attributable to El Paso Pipeline Partners, L.P.	123	126	124	139	512
Limited Partners' Net Income per Unit	0.57	0.50	0.46	0.51	2.03

(1) Retrospectively adjusted as discussed in Note 3.

**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.

**EL PASO PIPELINE PARTNERS, L.P.**

Registrant (a Delaware Limited Partnership)

By: **EL PASO PIPELINE GP COMPANY, L.L.C.**

Its sole General Partner

By: /s/ KIMBERLY A. DANG

Kimberly A. Dang,  
Vice President and Chief Financial Officer  
(principal financial and accounting officer)

Date: February 25, 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.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ KIMBERLY A. DANG</u> Kimberly A. Dang	Vice President and Chief Financial Officer	February 25, 2013
<u>/s/ RICHARD D. KINDER</u> Richard D. Kinder	Director, Chairman and Chief Executive Officer	February 25, 2013
<u>/s/ C. PARK SHAPER</u> C. Park Shaper	Director and President	February 25, 2013
<u>/s/ STEVEN J. KEAN</u> Steven J. Kean	Director, Executive Vice President and Chief Operating Officer	February 25, 2013
<u>/s/ THOMAS A. MARTIN</u> Thomas A. Martin	Director and Vice President (President, Natural Gas Pipelines)	February 25, 2013
<u>/s/ RONALD L. KUEHN JR.</u> Ronald L. Kuehn, Jr.	Director	February 25, 2013
<u>/s/ ARTHUR C. REICHSTETTER</u> Arthur C. Reichstetter	Director	February 25, 2013
<u>/s/ WILLIAM A. SMITH</u> William A. Smith	Director	February 25, 2013