ENTERPRISE PRODUCTS PARTNERS L P
Form 10-K
March 01, 2013
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.
(Exact name of Registrant as Specified in Its Charter)

DELAWARE	76-0568219
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

1100 LOUISIANA STREET, 10th FLOOR, HOUSTON, TEXAS 77002
(Address of Principal Executive Offices) (Zip Code)

(713) 381-6500
(Registrant's Telephone Number, Including Area Code)

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

Title of Each Class	Name of Each Exchange On Which Registered
Common Units	New York Stock Exchange

Securities to be 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 þ   No o

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer þ Accelerated filer o   Non-accelerated filer   o   Smaller reporting company o

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

The aggregate market value of the partnership's common units held by non-affiliates at June 29, 2012, the last business day of the registrant's most recently completed second fiscal quarter, based on the closing price on that date of $51.24 on the New York Stock Exchange Composite ticker tape, was $28.2 billion. There were 898,806,912 common units and 4,520,431 Class B units (which generally vote together with the common units) outstanding at January 31, 2013.

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KEY REFERENCES USED IN THIS REPORT

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Texas limited liability company.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director and Chairman of the Board of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company, a Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

As generally used in the energy industry and in this annual report, the acronyms below have the following meanings:

/d	= per day	MMBbls	= million barrels
BBtus	= billion British thermal units	MMBPD	= million barrels per day
Bcf	= billion cubic feet	MMBtus	= million British thermal units
BPD	= barrels per day	MMcf	= million cubic feet
MBPD	= thousand barrels per day	TBtus	= trillion British thermal units

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This annual report on Form 10-K for the year ended December 31, 2012 (our "annual report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Part I, Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

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PART I

Item 1 and 2. Business and Properties.

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and the Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals; crude oil gathering and transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 50,000 miles of onshore and offshore pipelines; 200 MMBbls of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 Bcf of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 21 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and export terminals, and octane enhancement and high-purity isobutylene production facilities.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP manages our partnership and owns a non-economic general partner interest in us. Our principal executive offices are located at 1100 Louisiana Street, 10th Floor, Houston, Texas 77002, our telephone number is (713) 381-6500 and our website address is www.enterpriseproducts.com.

We completed mergers with our affiliates Duncan Energy Partners L.P. ("Duncan Energy Partners") and Enterprise GP Holdings L.P. ("Holdings") in September 2011 and November 2010, respectively. We believe these recent merger transactions streamlined and simplified our organizational structure to be more transparent to investors, removed potential conflicts of interest due to common control considerations and reduced public company overhead costs. For additional information regarding these business combinations, see "Duncan and Holdings Mergers" within this Item 1 and 2 discussion.

We completed the merger of TEPPCO Partners, L.P. ("TEPPCO") and its general partner with our wholly-owned subsidiaries in October 2009. TEPPCO was a publicly traded energy logistics company that owned and operated a network of midstream energy assets. As a result of this merger, we acquired approximately 12,500 miles of pipelines that gather and transport refined petroleum products, crude oil, natural gas and NGLs.   In addition, we acquired our marine transportation business from TEPPCO.

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. As of February 1, 2013, there were approximately 6,600 EPCO personnel who spend all or a portion of their time engaged in our business. Approximately 6,400 of these individuals devote substantially all of their time to our affairs. For additional information regarding the ASA, see "—EPCO Administrative Services Agreement" under Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Business Strategy

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil in some of the largest supply basins in the U.S., Canada and the Gulf of Mexico with domestic consumers and international markets. Our business strategies are to:

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§ capitalize on expected increases in the production of natural gas, NGLs and crude oil from development activities in various producing basins including the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, deepwater Gulf of Mexico and developing shale plays, including the Barnett, Eagle Ford, Haynesville, Marcellus, Mancos and Utica Shales;

§ capitalize on expected demand growth for natural gas, NGLs, crude oil and petrochemical and refined products;

§ maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;

§ enhance the stability of our cash flows by investing in pipelines and other fee-based businesses; and

§ share capital costs and risks through joint ventures or alliances with strategic partners, including those that will provide the raw materials for these growth capital projects or purchase the projects' end products.

As noted above, part of our business strategy involves expansion through growth capital projects. We expect that these projects will enhance our existing asset base and provide us with additional growth opportunities in the future.

Major Customer

Our consolidated revenues are derived from a wide customer base. Our largest non-affiliated customer for 2012 was BP p.l.c. and its affiliates ("collectively, "BP"), which accounted for 9.5% of our consolidated revenues for this period. Our largest non-affiliated customer for 2011 and 2010 was Shell Oil Company and its affiliates, which accounted for 10.6% and 9.4% of our consolidated revenues during these years, respectively. For information regarding our revenue recognition policies, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

General Outlook for 2013

For information regarding our commercial and liquidity outlook for the year ending December 31, 2013, see "General Outlook for 2013" under Part II, Item 7 of this annual report.

Business Segments

The following sections provide an overview of our business segments, including information regarding principal products produced, services rendered, properties owned, seasonality and competition. We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. Our business segments are generally organized and managed according to the types of services rendered (or technologies employed) and products produced and/or sold.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity, L.P. ("Energy Transfer Equity"). For information about our former investment in Energy Transfer Equity, see Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Each of our business segments benefits from the supporting role of our related marketing activities. The main purpose of our marketing activities is to support the utilization of assets across our midstream energy network by increasing the volumes handled by such assets, which results in additional fee-based earnings for each business segment. In performing these support roles, our marketing activities also seek to take advantage of supply and demand opportunities in order to maximize earnings for the partnership. The financial results of our marketing efforts fluctuate period-to-period due to changes in volumes handled and overall market conditions, which may be influenced by current and forward market prices for the products bought and sold.

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For detailed financial information regarding our business segments (including our consolidated revenues by segment), see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. Such financial information is incorporated by reference into this Item 1 and 2 discussion. In addition, we utilize derivative instruments in connection with certain of our operations. For information regarding our use of derivative instruments, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Our results of operations and financial condition are subject to certain significant risks. For information regarding these risks, see Part I, Item 1A of this annual report. In addition, our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects of such laws and regulations on our business activities, see "Regulation" and "Environmental and Safety Matters" within this Item 1 and 2 discussion.

For management's discussion and analysis of our historical results of operations and a discussion of our liquidity and capital resources, see Part II, Item 7 of this annual report.

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our natural gas processing plants and related NGL marketing activities; approximately 16,700 miles of NGL pipelines; NGL and related product storage facilities; and 14 NGL fractionators. This segment also includes our NGL import and export terminal operations.

Purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline) are used as feedstocks by the petrochemical industry, as feedstocks by refineries in the production of motor gasoline and by industrial and residential consumers as fuel. Ethane is primarily used in the petrochemical industry as a feedstock for ethylene production, one of the basic building blocks for a wide range of plastics and other chemical products. Propane is used both as a petrochemical feedstock in the production of ethylene and propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of ethylene and butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to produce isobutane through isomerization. Isobutane is fractionated from mixed butane (a mixed stream of normal butane and isobutane) or produced from normal butane through the process of isomerization, and is used in refinery alkylation to enhance the octane content of motor gasoline, in the production of isooctane and other octane additives and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline or as a petrochemical feedstock.

Natural gas processing plants and related NGL marketing activities. At the core of our natural gas processing business are 24 processing plants located across Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming.

In its raw form, natural gas produced at the wellhead (especially in association with crude oil) contains varying amounts of mixed NGLs. Natural gas streams containing NGLs are usually not acceptable for transportation in natural gas pipelines or for commercial use as a fuel and must be sent to natural gas processing plants to remove the NGLs. Once the natural gas is processed with NGLs and impurities removed, the natural gas will meet pipeline and commercial quality specifications. On an energy equivalent basis, most NGLs generally have greater economic value as feedstock for petrochemical and motor gasoline production than their value as components of a natural gas stream.

Once the mixed component NGLs are extracted by a natural gas processing plant, they are typically transported to a centralized fractionation facility for separation into purity NGL products. The NGL products that we obtain through our processing arrangements (i.e., our equity NGL production volumes) or purchase directly from third parties are used in our NGL marketing activities to meet contractual requirements or sold on spot and forward markets. Also, we purchase raw natural gas streams from producers in connection with our natural gas processing activities. Once processed, this natural gas is available for sale through our natural gas marketing activities.

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In our natural gas processing business, we utilize contracts that are either fee-based, commodity-based or a combination of the two. When a cash fee for natural gas processing services is stipulated by a contract, we record revenue when a producer's natural gas has been processed and redelivered. In recent years, our portfolio of natural gas processing contracts has become increasingly weighted towards those with fee-based terms as producers seek to maximize the value of their production by retaining all or a portion of the NGLs extracted from their natural gas stream. We currently estimate that the terms of approximately 35% of our portfolio of natural gas processing contracts are entirely fee-based, with an additional 27% of this portfolio including a combination of fee-based and commodity-based terms. The terms of the remaining 38% of our portfolio of natural gas processing contracts are entirely commodity-based.

Our commodity-based contracts include keepwhole and margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts and contracts featuring a combination of commodity and fee-based terms. Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream while replacing the equivalent quantity of energy on a natural gas basis to producers. We recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. Under percent-of-liquids contracts, we take ownership of a portion of the mixed NGLs extracted from the producer's natural gas stream (in lieu of a cash processing fee) and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts. Under percent-of-proceeds contracts, we share in the proceeds generated from the sale of mixed NGLs we extract on the producer's behalf (in lieu of a cash processing fee). In certain cases, we also utilize contracts that include a combination of commodity-based terms (such as those described above) and fee-based terms.

Generally, our natural gas processing agreements have terms ranging from month-to-month to life of the producing lease. Intermediate terms of one to ten years are also common.

The value of natural gas lost as a result of NGL extraction (i.e., shrinkage) and consumed as plant fuel is referred to as plant thermal reduction ("PTR"), which is a significant cost of natural gas processing. To the extent that we are obligated under keepwhole and margin-band contracts to compensate the producer for shrinkage and plant fuel, we are exposed to fluctuations in the price of natural gas; however, margin-band contracts typically contain terms that limit our exposure to such risks. Under the terms of our other processing arrangements (i.e., those agreements with fee-based, percent-of-liquids and percent-of-proceeds terms), the producer typically bears the cost of PTR.

If the operating and extraction costs of natural gas processing plants are higher than the incremental value of the NGL products that would be extracted, then recovery levels of certain NGL products, principally ethane, may be purposefully reduced or eliminated. This scenario is typically referred to as "ethane rejection" and leads to a reduction in NGL volumes available for subsequent transportation, fractionation, storage and marketing. In general, contracts with keepwhole or percent-of-liquids terms provide us the right (but not the obligation) to process natural gas for a producer; thus, we are protected from processing natural gas at an economic loss during times when the sum of our costs exceeds the value of the equity NGL production we would obtain as consideration for processing services.

Our NGL marketing activities generate revenues from the sale and delivery of NGLs we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and contract purchases. The results of operations from our NGL marketing activities are primarily dependent upon the difference, or spread, between NGL sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for such factors as delivery location or NGL product quality. The prices of natural gas and NGLs are subject to fluctuations in response to changes in supply and demand and a variety of additional factors that are beyond our control. Periodically, we attempt to mitigate these price risks through the use of commodity derivative instruments.

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The following table presents selected information regarding our natural gas processing facilities at February 1, 2013:

Description of Asset	Location(s)	Our Ownership Interest		Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:					
Meeker	Colorado	100.0%		1.70	1.70
Pioneer (two facilities)	Wyoming	100.0%		1.35	1.35
Yoakum	Texas	100.0%		0.70	0.70
Toca	Louisiana	68.0%	(2)	0.66	1.10
Chaco	New Mexico	100.0%		0.60	0.60
North Terrebonne	Louisiana	60.0%	(2)	0.57	0.95
Neptune	Louisiana	66.0%	(2)	0.43	0.65
Pascagoula	Mississippi	40.0%	(2)	0.40	1.50
Thompsonville	Texas	100.0%		0.33	0.33
Shoup	Texas	100.0%		0.29	0.29
Sea Robin	Louisiana	40.0%	(2)	0.28	0.65
Gilmore	Texas	100.0%		0.25	0.25
Armstrong	Texas	100.0%		0.25	0.25
San Martin	Texas	100.0%		0.20	0.20
Delmita	Texas	100.0%		0.15	0.15
Carlsbad	New Mexico	100.0%		0.13	0.13
Sonora	Texas	100.0%		0.12	0.12
Shilling	Texas	100.0%		0.11	0.11
Venice	Louisiana	13.1%	(3)	0.10	0.75
Indian Springs	Texas	75.0%	(2)	0.09	0.12
Burns Point	Louisiana	50.0%	(2)	0.08	0.16
Indian Basin	New Mexico	42.4%	(2)	0.08	0.18
Chaparral	New Mexico	100.0%		0.04	0.04
Total processing capacities				8.91	12.28

(1) The approximate net gas processing capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) We proportionately consolidate our undivided interest in these operating assets.
(3) Our ownership in the Venice plant is held indirectly through our equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").

Our natural gas processing facilities can be characterized as two distinct types: (i) straddle plants situated on mainline natural gas pipelines owned either by us or by third parties or (ii) field plants that process natural gas from gathering pipelines. We operate all of our natural gas processing facilities except for the Pascagoula, Venice and Indian Basin plants. On a weighted-average basis, utilization rates for our natural gas processing plants were 55.9%, 56.1% and 51.2% during the years ended December 31, 2012, 2011 and 2010, respectively.

In May 2012, we announced that the first phase (or "train") of our new cryogenic natural gas processing plant at Yoakum, Texas commenced operations. The second train commenced operations in late August 2012. In the aggregate, these two processing trains are processing up to a combined 700 MMcf/d of natural gas and extracting over 90 MBPD of NGLs. The third and final train at the Yoakum facility, which is the same size as each of the first two trains, is currently undergoing commissioning operations and is expected to be fully operational in March 2013. The Yoakum facility processes natural gas produced primarily from the Eagle Ford Shale formation. In April 2012, we completed a 65-mile residue natural gas pipeline linking the Yoakum plant to our Wilson natural gas storage facility and numerous third party markets. In addition, we completed construction of 168 miles of pipelines that are part of our South Texas NGL Pipeline System that will transport mixed NGLs extracted at the Yoakum plant to our NGL fractionation and storage complex at Mont Belvieu, Texas.

Our NGL marketing activities utilize a fleet of approximately 670 railcars, the majority of which are leased from third parties. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the U.S. and parts of Canada. We have rail loading and unloading capabilities at certain of our terminal facilities in

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Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, New York, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

NGL pipelines. Our NGL pipelines transport mixed NGLs and other hydrocarbons from natural gas processing facilities, refineries and import terminals to fractionation plants and storage facilities; gather and distribute purity NGL products to and from fractionation plants, storage and terminal facilities, petrochemical plants, export facilities and refineries; and deliver propane to destinations along our various pipeline systems.

The results of operations from our NGL pipelines are primarily dependent upon the volume of NGLs transported and the associated fees we charge for such services. Transportation fees charged to shippers are based on either contractual arrangements or tariffs regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"). Excluding inventories owned in connection with our marketing activities, we typically do not take title to the products transported by our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

The following table presents selected information regarding our NGL pipelines at February 1, 2013:

Description of Asset	Location(s)	Our Ownership Interest		Length (Miles)
NGL pipelines:				
Mid-America Pipeline System (1)	Midwest and Western U.S.	100.0%		7,840
South Texas NGL Pipeline System	Texas	100.0%		1,598
Seminole Pipeline (1)	Texas	100.0%		1,373
Dixie Pipeline (1)	South and Southeastern U.S.	100.0%		1,306
Chaparral NGL System (1)	Texas, New Mexico	100.0%		1,011
Louisiana Pipeline System	Louisiana	100.0%		955
Skelly-Belvieu Pipeline (3)	Texas	50.0%	(2)	572
Promix NGL Gathering System	Louisiana	50.0%	(4)	360
Houston Ship Channel	Texas	100.0%		300
Rio Grande Pipeline (3)	Texas	70.0%	(5)	249
Panola Pipeline	Texas	100.0%		223
Lou-Tex NGL Pipeline (3)	Texas, Louisiana	100.0%		204
South Dean Pipeline	Texas	100.0%		186
Tri-States NGL Pipeline (3)	Alabama, Mississippi, Louisiana	83.3%	(6)	167
Chunchula Pipeline (3)	Alabama, Mississippi	100.0%		144
Others (five systems) (7)	Various	Various	(8)	242
Total miles				16,730

(1) Interstate and intrastate transportation services provided by these liquids pipelines are regulated by governmental agencies.
(2) Our ownership interest in the Skelly-Belvieu Pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu").
(3) Interstate transportation services provided by these liquids pipelines are regulated by governmental agencies.
(4) Our ownership interest in the Promix NGL Gathering System is held indirectly through our equity method investment in K/D/S Promix, L.L.C. ("Promix").
(5) We own a 70% consolidated interest in the Rio Grande Pipeline through our majority owned subsidiary, Rio Grande Pipeline Company.

(6) We own an 83.3% consolidated interest in the Tri-States NGL Pipeline through our majority owned subsidiary, Tri-States NGL Pipeline, L.L.C.
(7) Includes our Belle Rose and Wilprise pipelines located in the coastal regions of Louisiana and Mississippi; our two Port Arthur pipelines located in southeast Texas; and our Meeker pipeline in Colorado.
(8) We own a 74.7% consolidated interest in the 30-mile Wilprise pipeline through our majority owned subsidiary, Wilprise Pipeline Company, LLC. We proportionately consolidate our 50% undivided interest in a 45-mile segment of the Port Arthur pipelines. The remainder of these NGL pipelines are wholly owned.

As noted previously, certain of our NGL pipelines are subject to regulation. See "Regulation" within this Part I, Item 1 and 2 discussion for information regarding the general effects of governmental oversight on our liquids pipelines, including tariffs charged for transportation services.

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The maximum number of barrels that our NGL pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products being shipped and demand levels at various delivery points, the exact capacities of our NGL pipelines vary according to the particular operating conditions that exist at any given time. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 2,327 MBPD, 2,180 MBPD and 2,207 MBPD during the years ended December 31, 2012, 2011 and 2010, respectively.

The following information describes each of our principal NGL pipelines. We operate our NGL pipelines with the exception of the Tri-States pipeline.

§ The Mid-America Pipeline System is an NGL pipeline system consisting of four primary segments: the 2,920-mile Rocky Mountain pipeline, the 2,146-mile Conway North pipeline, the 621-mile Ethane-Propane Mix pipeline and the 2,153-mile Conway South pipeline. The Mid-America Pipeline System is present in 13 states: Colorado, Illinois, Iowa, Kansas, Minnesota, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Utah, Wisconsin and Wyoming. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs hub located on the Texas-New Mexico border. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. NGL hubs such as those at Hobbs and Conway provide buyers and sellers a centralized location for the storage and pricing of products, while also providing connections to intrastate and/or interstate pipelines. In addition, the Conway North segment has access to NGL supplies from Canada's Western Sedimentary Basin through third party connections. The Ethane-Propane Mix segment transports ethane/propane mix primarily to petrochemical plants in Iowa and Illinois from the NGL hub at Conway. The Conway South pipeline connects the Conway hub with Kansas refineries and provides bi-directional transportation of NGLs between Conway, Kansas and the Hobbs hub. The Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionation and storage facility at the Hobbs hub. This system connects to 19 non-regulated NGL terminals that we own and operate.

Volumes transported on the Mid-America Pipeline System originate from natural gas processing plants in the Rocky Mountain and Mid-Continent regions, as well as NGL fractionation and storage facilities in Kansas and Texas.

In March 2011, we announced an expansion project involving the Rocky Mountain segment of our Mid-America Pipeline System. The Rocky Mountain pipeline expansion involves looping the existing system with approximately 265 miles of 16-inch diameter pipeline, as well as pump station modifications. This expansion project is expected to add approximately 73 MBPD of transportation capacity to the Rocky Mountain pipeline's existing capacity of approximately 275 MBPD (after taking into account shipper commitments announced in January 2012). This expansion project is expected to begin service in the second quarter of 2014.

§ The South Texas NGL Pipeline System is a network of NGL gathering and transportation pipelines located in South Texas. The system gathers and transports mixed NGLs from natural gas processing plants in South Texas owned by us and our third party customers to our South Texas NGL fractionators, including those at our Mont Belvieu complex. In turn, the system transports purity NGL products from our South Texas NGL fractionators to refineries and petrochemical plants located between Corpus Christi, Texas and Houston, Texas and within the Texas City-Houston area, as well as to interconnects with common carrier NGL pipelines. The South Texas NGL Pipeline System also connects our South Texas NGL fractionators with our storage facility in Mont Belvieu, Texas.

We recently completed construction of 188 miles of NGL pipelines that are part of this system, including a 168-mile segment that transports mixed NGLs from our Yoakum, Texas natural gas processing plant to our Mont Belvieu NGL fractionation and storage complex. In addition, we are constructing a 173-mile NGL pipeline that will extend from our Yoakum facility to LaSalle County, Texas, and provide NGL connectivity to additional natural gas processing plants. This pipeline extension is expected to begin service during the second quarter of 2013.

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- The Seminole Pipeline transports NGLs from the Hobbs hub and the Permian Basin area of West Texas to markets in southeast Texas including our NGL fractionation facility in Mont Belvieu, Texas. NGLs originating on the Mid-America Pipeline System are the primary source of throughput for the Seminole Pipeline.

In March 2013, we expect to sell the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, to a third party for $87.1 million in cash. As a result, our first quarter of 2013 net income is expected to include an approximate $53 million gain from the disposal of these assets. The Seminole Pipeline remains connected to our Mont Belvieu complex through a newly constructed pipeline segment that we own.

- The Dixie Pipeline extends from southeast Texas and Louisiana to markets in the southeastern U.S. and transports propane and other NGLs. Propane supplies transported on this system primarily originate from southeast Texas, south Louisiana and Mississippi. This system operates in seven states: Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina and North Carolina and is connected to eight non-regulated propane terminals that we own and operate.

- The Chaparral NGL System transports NGLs from natural gas processing plants in West Texas and New Mexico to Mont Belvieu, Texas. This system consists of the 831-mile Chaparral pipeline and the 180-mile Quanah pipeline. As noted in the preceding table, interstate and intrastate transportation services provided by the Chaparral pipeline are regulated; however, transportation services provided by the Quanah pipeline are non-regulated.

- The Louisiana Pipeline System is a network of NGL pipelines located in southern Louisiana. This system transports NGLs originating in Louisiana and Texas to refineries and petrochemical plants located along the Mississippi River corridor in southern Louisiana. This system also provides transportation services for our natural gas processing plants, NGL fractionators and other assets located in Louisiana. Originating from a central point in Henry, Louisiana, pipelines extend westward to Lake Charles, Louisiana, northward to an interconnect with the Dixie Pipeline at Breaux Bridge, Louisiana and eastward in Louisiana, where our Promix, Norco and Tebone NGL fractionation and Sorrento storage facilities are located.

- The Skelly-Belvieu Pipeline transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. The Skelly-Belvieu Pipeline receives NGLs through a pipeline interconnect with our Mid-America Pipeline System in Skellytown, Texas.

- The Promix NGL Gathering System gathers mixed NGLs from natural gas processing plants in southern Louisiana for delivery to our Promix NGL fractionator.

- The Houston Ship Channel pipeline system connects our Mont Belvieu, Texas facilities with our Houston Ship Channel import/export terminals and various third party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel.

- The Rio Grande Pipeline transports mixed NGLs from near Odessa, Texas to a pipeline interconnect at the Mexican border south of El Paso, Texas.

- The Panola Pipeline transports mixed NGLs from northeast Texas near Carthage in Panola County to Mont Belvieu, Texas. The Panola Pipeline supports the Haynesville and Cotton Valley oil and gas production areas.

- The Lou-Tex NGL Pipeline system transports NGLs and refinery grade propylene between the Louisiana and Texas markets.

In September 2011, we announced the construction of a new NGL pipeline (the "Texas Express Pipeline") that would originate in Skellytown, Texas and extend approximately 580 miles to NGL fractionation and storage facilities in

Mont Belvieu, Texas. The Texas Express Pipeline is owned by Texas Express Pipeline LLC, a joint venture between us and affiliates of Enbridge Energy Partners, L.P. ("Enbridge"), Anadarko Petroleum Corporation

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("Anadarko") and DCP Midstream Partners LP ("DCP"). We will operate the Texas Express Pipeline. A separate joint venture between us and affiliates of Anadarko and Enbridge will construct two NGL gathering systems that will connect to the Texas Express Pipeline. Enbridge will operate these new NGL gathering systems. The Texas Express Pipeline and related NGL gathering systems are expected to begin service in the second quarter of 2013.

In January 2012, we announced the receipt of sufficient transportation commitments to support development of our 1,230-mile ATEX Express that will transport growing ethane production from the Marcellus and Utica Shale producing areas of Pennsylvania, West Virginia and Ohio to the U.S. Gulf Coast. We received additional volume commitments during the third quarter of 2012. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014.

In April 2012, we, along with WGR Asset Holding Company LLC, an affiliate of Anadarko, and DCP Midstream Front Range LLC formed a new joint venture, Front Range, to design and construct a new NGL pipeline that will originate in the Denver-Julesburg Basin (the "DJ Basin") in Weld County, Colorado and extend 435 miles to Skellytown in Carson County, Texas. The Front Range Pipeline, with connections to our Mid-America Pipeline System and the Texas Express Pipeline, will provide producers in the DJ Basin with access to the Gulf Coast, the largest NGL market in the U.S. We will construct and operate the pipeline, which is expected to begin service in the fourth quarter of 2013.

For additional information regarding the ATEX Express pipeline and Front Range joint venture, see "Significant Recent Developments" under Part II, Item 7 of this annual report.

NGL and related product storage facilities. We use underground storage caverns (or wells) and above ground storage tanks to store mixed NGLs and purity NGL, petrochemical and refined products owned by us and our customers. We collect storage revenues under our NGL and related product storage contracts based on the number of days a customer has volumes in storage multiplied by a storage fee (as defined in each contract). With respect to capacity reservation agreements, we collect a fee for reserving storage capacity for certain customers in our underground storage wells. Customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. When a customer exceeds its reserved capacity, we charge those customers an excess storage fee. In addition, we generally charge customers throughput fees based on volumes delivered into and subsequently withdrawn from storage. Accordingly, the results of operations from these assets are dependent upon the level of storage capacity reserved by customers, the volume of product delivered into and withdrawn from storage and the level of fees charged.

The following table presents selected information regarding our NGL and related product storage assets at February 1, 2013:

Storage Capacity by State	Net Usable Storage Capacity (MMBbls)
Texas (1)	123.6
Louisiana	12.9
Kansas	8.6
Mississippi	5.1
Others (2)	8.9
Total net usable storage capacity (3)	159.1

(1) The amount shown for Texas includes 35 underground NGL, petrochemical and refined

products storage caverns with an aggregate working capacity of approximately 100 MMBbls located in Mont Belvieu, Texas.

(2) Includes storage capacity at our facilities in Alabama, Arizona, California, Georgia, Illinois, Indiana, Iowa, Minnesota, Missouri, Nebraska, Nevada, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina and Wisconsin.

(3) Our underground storage caverns and above ground storage tanks have an aggregate 159.1 MMBbls of net usable storage capacity. Our aggregate net usable storage capacity includes 21.3 MMBbls held under long-term operating leases at facilities located in Indiana, Kansas, Louisiana and Texas. Approximately 1.5 MMBbls of our net usable storage capacity in Louisiana is held indirectly through our equity method investment in Promix. The remainder of our NGL underground storage caverns and above ground storage tanks are wholly owned.

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Our NGL and related product storage facilities are important components of our midstream energy infrastructure. We operate these facilities, with the exception of certain Louisiana storage locations, the leased Markham facility in Texas and a leased facility in Kansas that are operated for us by third parties. Our largest underground storage facility is located in Mont Belvieu, Texas. This facility consists of 35 underground storage caverns used to store and redeliver mixed NGLs and NGL purity, petrochemical and refined products for industrial customers located along the upper Texas Gulf Coast. The facility has an aggregate usable storage capacity of approximately 100 MMBbls, a brine system with approximately 20 MMBbls of above-ground brine storage pit capacity and two brine production wells.

NGL import and export facilities. Our NGL operations include import and export facilities located on the Houston Ship Channel in southeast Texas. We own an import and export facility located on land we lease from Oiltanking Houston LP. Our import facility can offload NGLs from tanker vessels at rates up to 14,000 barrels per hour depending on the product. Our export facility can load cargoes of refrigerated propane and butane onto tanker vessels at rates up to 6,700 barrels per hour. Our average combined NGL import and export volumes were 132 MBPD, 95 MBPD and 103 MBPD during the years ended December 31, 2012, 2011 and 2010, respectively.

In March 2011, we announced an expansion of our primary Houston Ship Channel import/export terminal. This expansion project is expected to increase the terminal's fully refrigerated export loading capacity for propane and other NGLs to approximately 15,000 barrels per hour, while also enhancing the terminal's ability to load multiple vessels simultaneously. We expect to complete this expansion project in the first quarter of 2013. The expanded facility provides customers with improved access to export domestically produced NGLs to growing international markets.

In addition to our Houston Ship Channel import/export terminal, we own a barge dock also located on the Houston Ship Channel that can load or offload two barges of NGLs or other products simultaneously at rates up to 5,000 barrels per hour. We also own an NGL terminal in Providence, Rhode Island that includes 0.4 MMBbls of refrigerated tank storage capacity and ship unloading capabilities at rates of up to 11,800 barrels per hour.

NGL fractionation. We own or have interests in 14 NGL fractionators located primarily in Texas and Louisiana. NGL fractionators separate mixed NGL streams into purity NGL products. The primary sources of mixed NGLs fractionated in the U.S. are domestic natural gas processing plants, crude oil refineries and imports of butane and propane mixtures. Mixed NGLs sourced from domestic natural gas processing plants and crude oil refineries are typically transported by NGL pipelines and, to a lesser extent, by railcar and truck to NGL fractionation facilities.

Mixed NGLs extracted by domestic natural gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from Gulf Coast, Rocky Mountain and Midcontinent natural gas processing plants, will be available for fractionation in commercially viable quantities for the foreseeable future. Significant volumes of mixed NGLs are contractually committed to be processed at our NGL fractionators by joint owners and third party customers.

Our NGL fractionation facilities process mixed NGL streams for third party customers and support our NGL marketing activities. We typically earn revenues from NGL fractionation under fee-based arrangements, including a significant level of demand-based fees. These fees (usually stated in cents per gallon) are contractually subject to adjustment for changes in certain fractionation expenses (e.g., natural gas fuel costs). At our Norco facility in Louisiana, we perform fractionation services for certain customers under percent-of-liquids contracts.

The results of operations of our NGL fractionation business are generally dependent upon the volume of mixed NGLs fractionated and either the level of fractionation fees charged (under fee-based contracts) or the value of NGLs received (under percent-of-liquids arrangements). Our fee-based fractionation customers retain title to the NGLs that we process for them. To the extent we fractionate volumes for customers under percent-of-liquids contracts, we are exposed to fluctuations in NGL prices (i.e., commodity price risk). We attempt to mitigate these risks through the use of commodity derivative instruments such as forward sales contracts.

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The following table presents selected information regarding our NGL fractionation facilities at February 1, 2013:

Description of Asset	Location	Our Ownership Interest		Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:					
Mont Belvieu (six units) (2)	Texas	Various	(3)	433	485
Shoup and Armstrong	Texas	100.0%		98	98
Hobbs	Texas	100.0%		75	75
Norco	Louisiana	100.0%		75	75
Promix	Louisiana	50.0%	(4)	73	145
BRF	Louisiana	32.2%	(5)	19	60
Tebone	Louisiana	56.2%	(6)	17	30
Todhunter	Ohio	100.0%		3	3
Total plant fractionation capacities				793	971

(1) The approximate net plant capacity does not necessarily correspond to our ownership interest in each facility. It is based on a variety of factors such as the level of volumes an owner processes at the facility and its ownership interest in the facility.
(2) There are six NGL fractionators located at our Mont Belvieu, Texas facility. Our sixth NGL fractionator commenced commercial operations at this facility in November 2012.
(3) We proportionately consolidate our 75% undivided interest in four of the NGL fractionators located at our Mont Belvieu, Texas facility. The remaining two units are wholly owned.
(4) Our ownership interest in the Promix fractionator is held indirectly through our equity method investment in Promix.
(5) Our ownership interest in the BRF fractionator is held indirectly through our equity method investment in Baton Rouge Fractionators LLC ("BRF").
(6) We proportionately consolidate our undivided interest in the Tebone fractionator.

On a weighted-average basis, utilization rates for our NGL fractionators were 91.9%, 90.2% and 90.7% during the years ended December 31, 2012, 2011 and 2010, respectively.

The following information describes each of our principal NGL fractionators. We operate all of our NGL fractionators.

§ Our Mont Belvieu NGL fractionation facility is located in Mont Belvieu, Texas, which is a key hub of the NGL industry. This facility fractionates mixed NGLs from several major NGL supply basins in North America, including the Mid-Continent, Permian Basin, San Juan Basin, Rocky Mountains, East Texas and the Gulf Coast. In early November 2012, construction of our sixth NGL fractionator at Mont Belvieu was completed and it commenced operations. This plant is supported by long-term customer commitments and has a capacity of approximately 85 MBPD. Completion of this plant increased the total NGL fractionation capacity at our Mont Belvieu complex to approximately 485 MBPD.

In March 2012, we announced plans to construct two additional NGL fractionators at our Mont Belvieu, Texas complex (NGL fractionators seven and eight) that are expected to provide us with 170 MBPD of incremental NGL fractionation capacity. The two new fractionation units (each with 85 MBPD of expected capacity) are forecast to commence operations during the fourth quarter of 2013 and support the continued growth of NGL production from resource basins such as the Eagle Ford Shale in Texas and various production areas in the Rocky Mountains and Mid-Continent. Once NGL fractionators seven and eight are constructed and placed in service, our total gross NGL fractionation capacity at Mont Belvieu (then eight units in total) would approximate 655 MBPD. At that time, our system-wide fractionation capacity is expected to exceed 1.0 MMBPD.

§ Our Shoup and Armstrong fractionators process mixed NGLs supplied by our South Texas natural gas processing plants. Purity NGL products from the Shoup and Armstrong fractionators are transported to local markets in the Corpus Christi area and also to Mont Belvieu, Texas using our South Texas NGL Pipeline System.

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- § Our Hobbs NGL fractionator is located in Gaines County, Texas, where it serves demand for NGLs in West Texas, New Mexico, California and northern Mexico. The Hobbs fractionator receives mixed NGLs from several major supply basins, including Mid-Continent, Permian Basin, San Juan Basin and the Rocky Mountains. The facility is located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, thus providing us the flexibility to supply the nation's largest NGL hub at Mont Belvieu, Texas as well as access to the second-largest NGL hub at Conway, Kansas.

- § Our Norco NGL fractionator receives mixed NGLs via pipeline from refineries and natural gas processing plants located in southern Louisiana and along the Mississippi and Alabama Gulf Coast, including from our Pascagoula, Venice and Toca facilities.

- § The Promix NGL fractionator receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including from our Neptune, Burns Point and Pascagoula facilities. In addition to the Promix NGL Gathering System (described previously), Promix owns three NGL storage caverns and a barge loading facility that are important to its operations. Promix leases a fourth NGL storage cavern.

- § The BRF fractionator receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana.

Seasonality. Our natural gas processing and NGL fractionation operations typically exhibit little to no seasonal variation. Our NGL marketing activities rely on inventories of purity NGL products. Propane and normal butane inventories are typically at higher levels from March through November since these products are normally in higher demand and at higher price levels during the winter months. Ethane, isobutane and natural gasoline inventories are generally stable and less cyclical throughout the year.

NGL pipeline transportation volumes are generally higher from October through March due to higher demand for propane (for residential heating) and normal butane (for blending into motor gasoline). With respect to our NGL and related product storage facilities, we usually experience an increase in demand for storage services during the spring and summer months due to increased feedstock storage requirements for motor gasoline production and a decrease during the fall and winter months when propane inventories are being drawn down for heating needs. Likewise, the revenues we recognize from NGL marketing activities are predicated on the overall demand for such products, which may fluctuate due to seasonal needs for gasoline blending feedstocks, heating requirements and similar factors. In general, our import volumes peak during the spring and summer months and our export volumes are typically at their highest levels during the winter months. Lastly, our facilities located along the Gulf Coast of the U.S. may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their respective market areas, our natural gas processing business activities and related NGL marketing activities encounter competition from fully integrated oil companies, intrastate pipeline companies, major interstate pipeline companies and their non-rate regulated affiliates, financial institutions with trading platforms and independent processors. Each of our marketing competitors has varying levels of financial and personnel resources, and competition generally revolves around price, quality of customer service and proximity to customers and other market hubs. In the markets served by our NGL pipelines, we compete with a number of intrastate and interstate pipeline companies (including those affiliated with major oil, petrochemical and natural gas companies) and barge, rail and truck fleet operations. In general, our NGL pipelines compete with these entities in terms of transportation fees, reliability and quality of customer service.

Our primary competitors in the NGL and related product storage businesses are integrated major oil companies, chemical companies and other storage and pipeline companies. We compete with other storage service providers primarily in terms of the fees charged, number of pipeline connections provided and operational dependability. Our import and export operations compete with those operated by major oil and chemical companies primarily in terms of loading and offloading throughput capacity.

We compete with a number of NGL fractionators in Texas, Louisiana, New Mexico and Kansas. Competition for such services is primarily based on the fractionation fee charged. However, the ability of an NGL

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fractionator to receive a customer's mixed NGLs and store and distribute its purity NGL products is also an important competitive factor and is a function of having the necessary pipeline and storage infrastructure.

Onshore Natural Gas Pipelines & Services

Our Onshore Natural Gas Pipelines & Services business segment includes approximately 19,900 miles of onshore natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. We lease underground salt dome natural gas storage facilities located in Texas and Louisiana and own an underground salt dome storage cavern in Texas, all of which are important to our natural gas pipeline operations. This segment also includes our related natural gas marketing activities.

Onshore natural gas pipelines. Our onshore natural gas pipeline systems gather and transport natural gas from major producing regions such as the Eagle Ford Shale, Haynesville Shale, San Juan, Barnett Shale, Permian, Piceance and Greater Green River supply basins. In addition, certain of these pipeline systems receive natural gas production from Gulf of Mexico developments through coastal pipeline interconnects with offshore pipelines. Our onshore natural gas pipelines receive natural gas from producers, other pipelines or shippers at the wellhead or through system interconnects and redeliver the natural gas to processing facilities, local gas distribution companies, industrial or municipal customers, storage facilities or to other onshore pipelines.

The results of operations from our onshore natural gas pipelines and related storage assets are primarily dependent upon the volume of natural gas transported or stored, the level of firm capacity reservations made by shippers, and the associated fees we charge for such activities. Transportation fees charged to shippers (typically per MMBtu of natural gas) are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. Certain of our onshore natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractual fee based on the level of throughput capacity reserved (whether or not the shipper actually utilizes such capacity). Under our natural gas storage contracts, there are typically two components of revenues: (i) monthly demand payments, which are associated with a customer's storage capacity reservation and paid regardless of actual usage, and (ii) storage fees per unit of volume stored at our facilities.

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The following table presents selected information regarding our onshore natural gas pipelines and related storage assets at February 1, 2013:

Description of Asset	Location(s)	Our Ownership Interest		Length (Miles)	Approximate Net Capacity Pipelines (MMcf/d)	Approximate Net Capacity Usable Storage (Bcf)
Onshore natural gas pipelines and related storage assets:						
Texas Intrastate System (1)	Texas	Various	(2)	8,459	6,640	12.9
Acadian Gas System (1)	Louisiana	100.0%	(3)	1,323	3,100	1.3
Jonah Gathering System	Wyoming	100.0%		924	2,550	--
San Juan Gathering System	New Mexico, Colorado	100.0%		6,170	1,750	--
Piceance Basin Gathering System	Colorado	100.0%		190	1,600	--
White River Hub (4)	Colorado	50.0%	(5)	10	1,500	--
Haynesville Gathering Systems	Louisiana, Texas	100.0%		314	1,300	--
Fairplay Gathering System	Texas	100.0%		250	285	--
Carlsbad Gathering System	Texas, New Mexico	100.0%		953	220	--
Indian Springs Gathering System	Texas	80.0%	(6)	199	160	--
Delmita Gathering System	Texas	100.0%		239	145	--
South Texas Gathering System	Texas	100.0%		648	143	--
Big Thicket Gathering System (7)	Texas	100.0%		253	60	--
Total				19,932		14.2

(1) Intrastate and interstate-sourced volumes transported by these systems are regulated by governmental agencies.
(2) Of the 8,459 miles comprising the Texas Intrastate System, we lease 265 miles from a third party. We proportionately consolidate our undivided interests, which range from 22% to 80%, in 1,262 miles of pipeline. Our Wilson natural gas storage facility consists of five underground salt dome natural gas storage caverns with 12.9 Bcf of usable storage capacity, four of which (comprising 6.9 Bcf of usable capacity) are held under an operating lease that expires in January 2028. The remainder of our Texas Intrastate System is wholly owned.
(3) The Acadian Gas System is wholly owned except for an underground salt dome natural gas storage facility that we hold under an operating lease that expires in December 2018.
(4) Interstate volumes at this facility are regulated by governmental agencies.
(5) Our ownership interest in the White River Hub facility is held indirectly through our equity method investment in White River Hub, LLC ("White River Hub").
(6) We proportionately consolidate our undivided interest in the Indian Springs Gathering System.
(7) Intrastate volumes transported by this pipeline are regulated by governmental agencies.

In December 2011, we sold our natural gas storage facilities in Petal and Hattiesburg, Mississippi that were owned by Crystal Holding L.L.C. for $550.0 million in cash, before working capital adjustments. For more information regarding the sale of our Mississippi natural gas storage facilities, see "Significant Recent Developments—Sale of Our Mississippi Natural Gas Storage Facilities" included under Part II, Item 7 of this annual report. In August 2011, we sold our Alabama Intrastate System for $21.8 million in cash, before working capital adjustments. Neither of these assets were integrated with our other natural gas pipeline or storage assets.

As noted previously, certain of our natural gas pipelines are subject to regulation. See "Regulation" within this Part I, Item 1 and 2 discussion for information regarding the general effects of governmental oversight on our natural gas pipelines, including tariffs charged for transportation services.

On a weighted-average basis, aggregate utilization rates for our onshore natural gas pipelines were approximately 67.7%, 64.6% and 64.2% during the years ended December 31, 2012, 2011 and 2010, respectively. Such utilization rates represent actual natural gas volumes delivered as a percentage of our nominal delivery capacity and do not reflect firm capacity reservation agreements where throughput capacity is reserved whether or not the shipper actually utilizes such capacity.

The following information describes each of our principal onshore natural gas pipelines. With the exception of the White River Hub and certain minor segments of the Texas Intrastate System, we operate our onshore natural gas pipelines and storage facilities.

§ The Texas Intrastate System is comprised of the 7,070-mile Enterprise Texas pipeline system, the 632-mile Channel pipeline system, the 630-mile Waha gathering system and the 127-mile TPC Offshore gathering

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system. The Wilson natural gas storage facility, which is an important part of the Texas Intrastate System, is comprised of a network of underground salt dome storage caverns located in Wharton County, Texas.

The Texas Intrastate System gathers, transports and stores natural gas from supply basins in Texas such as the Eagle Ford Shale and Barnett Shale for redelivery to local gas distribution companies and electric generation and industrial and municipal consumers as well as to connections with intrastate and interstate pipelines. The Texas Intrastate System serves commercial markets in Texas, including Corpus Christi, the San Antonio/Austin area, the Beaumont/Orange area and the Houston area, including the Houston Ship Channel industrial market.

§ The Acadian Gas System transports, stores and markets natural gas in Louisiana. The Acadian Gas System is comprised of the 587-mile Cypress pipeline, 442-mile Acadian pipeline, 268-mile Haynesville Extension and 26-mile Enterprise Pelican pipeline. The Acadian Gas System includes a leased underground salt dome natural gas storage cavern located at Napoleonville, Louisiana. The Acadian Gas System links natural gas supplies from Louisiana (e.g., from Haynesville Shale supply basin) and offshore Gulf of Mexico developments with gas distribution companies, electric generation plants and industrial customers located primarily in the Baton Rouge – New Orleans – Mississippi River corridor.

In November 2011, commercial operations on the Haynesville Extension of our Acadian Gas System commenced. As a result of completing the Haynesville Extension project, we provided producers in Louisiana's Haynesville and Bossier Shale plays with access to 1.8 Bcf/d of incremental natural gas takeaway capacity. As an extension of our Acadian Gas System, the Haynesville Extension offers producers access to more than 150 end-user customer service locations along the Mississippi River industrial corridor between Baton Rouge and New Orleans, as well as the Henry Hub. The Haynesville Extension features interconnects with 12 interstate pipeline systems and is the only southerly option that avoids potential natural gas supply bottlenecks at the Perryville Hub and offers producers flow assurance and market choice to assist in maximizing the value of their natural gas production. In general, the Henry Hub and Perryville Hub are distribution points along natural gas pipelines that provide shippers with connections to other intrastate and/or interstate pipelines, as well as serve as pricing locations.

§ The Jonah Gathering System is located in the Greater Green River Basin of southwest Wyoming. This system gathers natural gas from the Jonah and Pinedale supply fields for delivery to regional natural gas processing plants, including our Pioneer facilities, for ultimate delivery into major interstate pipelines.

§ The San Juan Gathering System serves producers in the San Juan Basin of northern New Mexico and southern Colorado. This system gathers natural gas from production wells located in the San Juan Basin and delivers the natural gas either directly into major interstate pipelines or to regional processing and treating plants, including our Chaco processing facility and Val Verde treating plant located in New Mexico, for ultimate delivery into major interstate pipelines.

§ The Piceance Basin Gathering System consists of a network of gathering pipelines located in the Piceance Basin of northwestern Colorado. The Piceance Basin Gathering System gathers natural gas throughout the Piceance Basin to our Meeker natural gas processing complex for ultimate delivery into the White River Hub and other major interstate pipelines.

§ The White River Hub is a natural gas hub facility serving producers in the Piceance Basin of northwest Colorado. The facility enables producers to access six interstate natural gas pipelines and has a gross throughput capacity of 3 Bcf/d of natural gas.

§ The Haynesville Gathering Systems consist of the 190-mile State Line gathering system, the 78-mile Southeast Mansfield gathering system and the 46-mile Southeast Stanley gathering system. Our Haynesville Gathering Systems gather natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations in Louisiana and eastern Texas for delivery to several downstream markets including the Haynesville Extension of our Acadian Gas System.

- The Fairplay Gathering System gathers natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations within Panola and Rusk Counties in East Texas. This system is expected to extend our asset base through potential future interconnects with our Texas Intrastate System, support deliveries of NGLs into our Panola liquids pipeline and further to our fractionation, storage and distribution complex in Mont Belvieu, Texas.

- The Carlsbad Gathering System gathers natural gas from the Permian Basin region of Texas and New Mexico for delivery to natural gas processing plants, including our Chaparral and Carlsbad plants, as well as delivery into the El Paso Natural Gas and Transwestern pipelines.

Natural gas marketing activities. Our natural gas marketing activities generate revenues from the sale and delivery of natural gas to local distribution companies, end-users and others purchased from producers, regional natural gas processing plants and the open market. The results of operations from our natural gas marketing activities are primarily dependent upon the difference, or spread, between natural gas sales prices and the associated purchase price and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location.

We are exposed to commodity price risk to the extent that we take title to natural gas volumes in connection with our natural gas marketing activities and certain intrastate natural gas transportation contracts. In addition, we purchase and resell natural gas for certain producers that use our San Juan, Carlsbad and Jonah Gathering Systems and certain segments of our Texas Intrastate System. Also, several of our natural gas gathering systems, while not providing marketing services, have some exposure to risks related to fluctuations in commodity prices through transportation arrangements with shippers. For example, nearly all of the transportation revenues generated by our San Juan Gathering System are based on a percentage of a regional price index for natural gas. This index is subject to change based on a variety of factors including natural gas supply and consumer demand. We use derivative instruments to mitigate our exposure to commodity price risks associated with our natural gas pipelines and services business.

Seasonality. Our onshore natural gas pipelines typically experience higher throughput rates during the summer months as utility companies that use natural gas for power generation increase their electricity output to meet residential and commercial demand for air conditioning. Higher throughput rates are also experienced in the winter months as natural gas is used to meet residential and commercial heating requirements. In addition, our facilities located along the U.S. Gulf Coast may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their market areas, our onshore natural gas pipelines compete with other natural gas pipelines on the basis of price (in terms of transportation fees), quality of customer service and operational flexibility. Our natural gas marketing activities compete primarily with other natural gas pipeline companies and their marketing affiliates and financial institutions with trading platforms. Competition in the natural gas marketing business is based primarily on competitive pricing, proximity to customers and market hubs, and quality of customer service.

Onshore Crude Oil Pipelines & Services

Our Onshore Crude Oil Pipelines & Services business segment includes approximately 5,100 miles of onshore crude oil pipelines, crude oil storage terminals located in Oklahoma and Texas, and our crude oil marketing activities.

Onshore crude oil pipelines. Our onshore crude oil pipeline systems gather and transport crude oil primarily in New Mexico, Oklahoma and Texas to refineries, centralized storage terminals and connecting pipelines. The results of operations from crude oil transportation services are primarily dependent upon the volume of crude oil transported and the level of fees charged to shippers (typically per barrel of crude oil). Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements.

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The following table presents selected information regarding our onshore crude oil pipelines at February 1, 2013:

Description of Asset	Location(s)	Our Ownership Interest	Pipeline Length (Miles)
Crude oil pipelines:			
Seaway Pipeline (1)	Texas, Oklahoma	50.0% (2)	567
Red River System (1)	Texas, Oklahoma	100.0%	1,859
South Texas Crude Oil Pipeline System (3)	Texas	100.0%	1,119
West Texas System (1)	Texas, New Mexico	100.0%	772
Basin Pipeline (1)	Texas, New Mexico, Oklahoma	13.0% (4)	519
Other (three systems) (5)	Texas, New Mexico	100.0%	230
Total miles			5,066

(1) Interstate and intrastate transportation services provided by these liquids pipelines are regulated by governmental agencies.
(2) Our ownership interest in the Seaway Pipeline is held indirectly through our equity method investment in Seaway Crude Pipeline Company LLC ("Seaway").
(3) Intrastate transportation services provided by these liquids pipelines are regulated by governmental agencies.
(4) We proportionately consolidate our undivided interest in the Basin Pipeline.
(5) Includes our Azelea and Sharon Ridge crude oil gathering systems located in Texas and Mesquite pipeline in New Mexico.

The maximum number of barrels that our onshore crude oil pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon product composition and demand levels at various delivery points, the exact capacities of our onshore crude oil pipelines vary according to the particular operating conditions that exist at any given time. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 828 MBPD, 678 MBPD and 670 MBPD during the years ended December 31, 2012, 2011 and 2010, respectively.

As noted previously, certain of our crude oil pipelines are subject to regulation. See "Regulation" within this Part I, Item 1 and 2 discussion for information regarding the general effects of governmental oversight on our liquids pipelines, including tariffs charged for transportation services.

The following information describes each of our principal onshore crude oil pipelines, all of which we operate with the exception of the Basin Pipeline.

§ The Seaway Pipeline connects the Cushing, Oklahoma hub with markets in Southeast Texas. The Seaway Pipeline is comprised of the Longhaul 30-inch System, the Freeport System and the Texas City System. The Longhaul 30-inch System includes an approximately 500-mile, 30-inch diameter pipeline that provides north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal, which is near Freeport, Texas, and an Enterprise terminal located near Katy, Texas. The Cushing hub is a major industry trading hub and price settlement point for West Texas Intermediate on the New York Mercantile Exchange.

In early 2012, Seaway undertook a reversal of the flow of its Longhaul 30-inch System and began providing north-to-south transportation service in May 2012. Previously, this pipeline was used to transport crude oil in the opposite direction from the Jones Creek terminal to the Cushing hub.

The Freeport System consists of a ship unloading dock, three pipelines and other related facilities that transport crude oil from Freeport, Texas to the Jones Creek terminal. The Texas City System consists of a ship unloading dock, storage tanks, various pipelines and other related facilities that deliver crude oil from Texas City, Texas to Galena Park, Texas and other nearby locations. The Freeport System and Texas City System make only intrastate movements. Seaway also owns storage tanks at the Jones Creek terminal, which are connected to the Longhaul 30-inch System. In total, the Texas City System and Jones Creek Terminal include 6.7 MMBbls of crude oil storage tank capacity (3.4 MMBbls net to our ownership interest).

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In January 2013, Seaway made certain pump station additions and modifications at its Cushing origin. In the fourth quarter of 2013, Seaway expects to place into service a 65-mile lateral pipeline from Jones Creek to our ECHO terminal. In mid-year 2014, Seaway plans to extend this lateral pipeline by 85 miles to the Beaumont/Port Arthur, Texas area, which would provide shippers access to the region's heavy oil refining capabilities. Seaway is also planning a further expansion of its pipeline system by adding an additional 512-mile, 30-inch pipeline between Cushing and Jones Creek. That expansion is expected to go into service in the first quarter of 2014. In all, Seaway plans to invest more than $2 billion on these expansions.

As noted above, the Longhaul 30-inch System was placed into new north-to-south transportation service in May 2012. During the initial period of operations from May 2012 through December 2012, the throughput of this line averaged 132 MBPD. As a result of the January 2013 expansion described above, Seaway's capacity is expected to increase; however, Seaway currently lacks sufficient operational experience to identify what the precise capacity of the Longhaul 30-inch System will be when it is placed into full commercial service. In addition, the capacity will depend on the type and mix of crude oil transported.

The capacity of the Freeport System is approximately 220 MBPD. The capacity of the Texas City System is approximately 500 MBPD.

§ The Red River System transports crude oil from North Texas to southern Oklahoma for delivery to either two local refineries or pipeline interconnects for further transportation to Cushing, Oklahoma. The Red River System is connected to 1.2 MMBbls of crude oil storage capacity that we own and operate.

§ The South Texas Crude Oil Pipeline System transports crude oil originating in South Texas, including production from the Eagle Ford Shale supply basin, to refineries in the Greater Houston area. In June 2012, we announced that the Eagle Ford expansion of our South Texas Crude Oil Pipeline System commenced operations. This pipeline expansion, which has a crude oil transportation capacity of 350 MBPD, allows us to serve growing production areas in the Eagle Ford Shale supply basin. The new pipeline originates at our Lyssy station in Karnes County, Texas and extends 147 miles to Sealy, Texas and includes 2.4 MMBbls of crude oil storage, including 0.8 MMBbls in Karnes County, Texas, 0.4 MMBbls in Gonzales County, Texas and 1.2 MMBbls at Sealy. Crude oil supplies arriving at Sealy on the new pipeline are being delivered to Houston area refiners through affiliate and third party owned pipelines. In addition, shippers have access to our new ECHO crude oil storage terminal.

Including the storage capacity associated with the Eagle Ford expansion, the South Texas Crude Oil Pipeline System is connected to 3.5 MMBbls of crude oil storage capacity that we own and operate.

§ The West Texas System connects crude oil gathering systems in West Texas and southeast New Mexico to our terminal facility in Midland, Texas. The West Texas System is connected to 0.4 MMBbls of crude oil storage capacity that we own and operate.

§ The Basin Pipeline transports crude oil from the Permian Basin in West Texas and southern New Mexico to Cushing, Oklahoma. The Basin Pipeline includes 5 MMBbls of crude oil storage capacity (or 0.8 MMBbls net to our ownership interest).

In August 2012, we announced the formation of a 50/50 joint venture, Eagle Ford Pipeline LLC, with Plains All American Pipeline, L.P. ("Plains") to provide crude oil pipeline services to producers in South Texas. The joint venture's crude oil pipeline system, which is currently under construction, is expected to have 350 MBPD of throughput capacity and 1.8 MMBbls of operational storage capacity. The joint venture's assets will also include a marine terminal facility at Corpus Christi, Texas. Portions of the new pipeline system are expected to be placed into service during the first quarter of 2013, with the balance of the system expected to be placed into service in the third quarter of 2013. Plains will serve as operator of the joint venture's pipeline system.

Crude oil terminals. We own crude oil terminals located in Cushing, Oklahoma, Houston, Texas and Midland, Texas that are used to store crude oil for us and our customers. The results of operations from crude oil terminaling services are primarily dependent upon the level of volumes a customer stores at each terminal and the

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length of time such storage occurs, including the level of firm storage capacity reserved (if any), pumpover volumes, and the fees associated with each activity. Fees associated with firm storage capacity reservation agreements are charged to a customer regardless of the volume the customer actually stores at the terminal.

The following table presents selected information regarding our crude oil terminals at February 1, 2013:

Description of Asset	Location(s)	Our Ownership Interest	Net Usable Storage Capacity (MMBbls)
Crude oil terminals:			
ECHO terminal	Texas	100.0%	0.5
Cushing terminal	Oklahoma	100.0%	3.1
Midland terminal	Texas	100.0%	1.5
Total capacity			5.1

The following information describes each of our principal crude oil storage terminals, all of which we operate.

§ The ECHO terminal, or Enterprise Crude Houston storage terminal, is located in southeast Houston, Texas and provides our customers with access to major refiners located in the Houston and Texas City area representing more than 2 MMBPD of refining capacity. The ECHO terminal also has connections to marine facilities that provide connectivity to any refinery on the U.S. Gulf Coast. We developed the ECHO terminal to support the expansion of our South Texas Crude Oil Pipeline System and the reversal of the Seaway Pipeline. We own and operate the ECHO terminal.

In November 2012, the initial phase of our ECHO storage terminal was partially completed and began receiving deliveries of crude oil. Completion of this first phase provides us with approximately 0.5 MMBbls of crude oil storage capacity (two tanks) at the site. A third tank was completed and placed into service in February 2013. An additional 0.9 MMBbls of storage capacity is expected to be in service as early as the second quarter of 2014. When fully developed, we estimate that the ECHO terminal could have up to 6.0 MMBbls of crude oil storage capacity.

§ The Cushing terminal provides crude oil storage, pumpover and trade documentation services. Our terminal in Cushing, Oklahoma has 19 above-ground storage tanks with aggregate crude oil storage capacity of 3.1 MMBbls.

§ The Midland terminal provides crude oil storage, pumpover and trade documentation services. The Midland, Texas terminal has an aggregate storage capacity of 1.5 MMBbls through the use of 12 above-ground storage tanks.

Crude oil marketing activities. Our crude oil marketing activities generate revenues from the sale and delivery of crude oil purchased either directly from producers or from others on the open market. The results of operations from our crude oil marketing activities are primarily dependent upon the difference, or spread, between crude oil sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for such factors as delivery location or crude oil quality. In order to limit the exposure of our crude oil marketing activities to commodity price risk, our purchases and sales of crude oil are typically contracted to occur within the same calendar month. We also use derivative instruments to mitigate our exposure to commodity price risks associated with our crude oil marketing activities.

Other. In support of this business, we use a fleet of approximately 450 tractor-trailer tank trucks, the majority of which we lease and operate, to transport crude oil for us and third parties.

<u>Seasonality</u>. Seasonality has little to no impact on the results of operations from our onshore crude oil pipelines and terminals. However, our crude oil assets situated along the Texas Gulf Coast (e.g., the ECHO

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terminal) may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

Competition. Within their respective market areas, our onshore crude oil pipelines, terminals and related marketing activities compete with other crude oil pipeline companies, rail carriers, major integrated oil companies and their marketing affiliates, financial institutions with trading platforms and independent crude oil gathering and marketing companies. The onshore crude oil business can be characterized by strong competition for supplies of crude oil. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and other market hubs.

Offshore Pipelines & Services

Our Offshore Pipelines & Services business segment serves some of the most active drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama. This segment includes approximately 2,300 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms.

In April 2010, in an event unrelated to our operations, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill. As a result, governmental agencies took actions to halt most drilling operations in the Gulf of Mexico for a period of time extending into October 2010. The moratorium impacted the timing of exploration and production activities in the Gulf of Mexico, with such activities only recently nearing pre-moratorium levels. In general, regulations resulting from the Deepwater Horizon incident have made it more difficult for producers to obtain governmental approvals for offshore exploration and production activities. To the extent that new regulations or other governmental actions significantly curtail such exploration and production activities in the Gulf of Mexico, it could have a material adverse impact on our offshore operations. For additional information regarding this risk, see "Additional regulations that cause delays or deter new offshore oil and gas drilling could have a material adverse effect on our financial position, results of operations and cash flows" under Part I, Item 1A of this annual report.

Offshore natural gas and crude oil pipelines. Our offshore Gulf of Mexico pipelines provide for the gathering and transportation of natural gas or crude oil from offshore production fields to interconnecting offshore or onshore pipelines or processing facilities. The results of operations from these pipelines are primarily dependent upon the volume of natural gas or crude oil transported and the level of fees charged to shippers. Transportation fees are based either on contractual arrangements or, as in the case of our High Island Offshore System, tariffs regulated by the FERC. In general, contractual arrangements for offshore pipeline transportation services tend to be long-term in nature and involve life-of-reserve commitments.

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The following table presents selected information regarding our offshore natural gas pipelines at February 1, 2013:

Description of Asset	Our Ownership Interest		Pipeline Length (Miles)	Approximate Net Capacity (MMcf/d) (1)
Offshore natural gas pipelines:				
Independence Trail	100.0%		135	1,000
Viosca Knoll Gathering System	100.0%		137	600
High Island Offshore System	100.0%		287	500
Falcon Natural Gas Pipeline	100.0%		14	400
Green Canyon Laterals	Various	(2)	54	343
Anaconda Gathering System	100.0%		183	300
Manta Ray Offshore Gathering System	25.7%	(3)	220	205
Nautilus System	25.7%	(3)	101	154
Nemo Gathering System	33.9%	(4)	24	102
VESCO Gathering System	13.1%	(5)	125	60
Total miles			1,280	

(1) Amounts presented are net to our ownership interest.
(2) We proportionately consolidate our undivided interests, which range from 2.7% to 33.3%, in 47 miles of the Green Canyon Lateral pipelines. The remainder of the laterals are wholly owned.
(3) Our ownership interests in the Manta Ray Offshore Gathering System and the Nautilus System are held indirectly through our equity method investment in Neptune Pipeline Company, L.L.C. ("Neptune").
(4) Our ownership interest in the Nemo Gathering System is held indirectly through our cost method investment in Nemo Gathering Company, LLC ("Nemo").
(5) Our ownership interest in the VESCO Gathering System is held indirectly through our equity method investment in VESCO. This system is important to our natural gas processing operations; therefore, our equity method investment in VESCO is accounted for under our NGL Pipelines & Services business segment.

On a weighted-average basis, aggregate utilization rates for our offshore natural gas pipelines were approximately 21.7%, 27.4% and 23.8% during the years ended December 31, 2012, 2011 and 2010, respectively.

The following information describes each of our principal offshore natural gas pipelines. We operate our Independence Trail pipeline, Viosca Knoll Gathering System, High Island Offshore System, Falcon Natural Gas Pipeline, Anaconda Gathering System and certain components of the Green Canyon Laterals. Third parties operate the remainder of our offshore natural gas pipelines.

§ The Independence Trail natural gas pipeline transports natural gas that originates at our Independence Hub platform and at a pipeline interconnect downstream of our Independence Hub platform. Our Independence Trail pipeline delivers natural gas to the Tennessee Gas Pipeline at a pipeline interconnect on our West Delta 68 platform. Natural gas transported on the Independence Trail pipeline originates from production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

§ The Viosca Knoll Gathering System gathers natural gas from producing fields located in the Main Pass, Mississippi Canyon and Viosca Knoll areas of the Gulf of Mexico for delivery to several major interstate pipelines, including the High Point Gas Transmission, Transco, Dauphin Island Gathering System, Tennessee Gas Pipeline and Destin Pipelines.

§ The High Island Offshore System ("HIOS") transports natural gas from producing fields located in the Galveston, Garden Banks, West Cameron, High Island and East Breaks areas of the Gulf of Mexico to the ANR pipeline system and Tennessee Gas Pipeline. HIOS includes 201 miles of pipeline and eight pipeline junction and service platforms that are regulated by the FERC. In addition, this system includes the 86-mile East Breaks Gathering System that connects HIOS to the Hoover-Diana deepwater platform located in Alaminos Canyon Block 25.

§ The Falcon Natural Gas Pipeline transports natural gas processed at our Falcon Nest platform to a connection with the Central Texas Gathering System located at the Brazos Addition Block 133 platform.

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§ The Green Canyon Laterals represent a collection of small diameter pipelines that gather natural gas for delivery to HIOS and various other downstream pipelines.

§ The Anaconda Gathering System gathers natural gas from producing fields located in the Green Canyon area of the Gulf of Mexico for delivery to our Nautilus System.

§ The Manta Ray Offshore Gathering System gathers natural gas from producing fields located in the Green Canyon, Southern Green Canyon, Ship Shoal, South Timbalier and Ewing Bank areas of the Gulf of Mexico for delivery to numerous downstream pipelines, including our Nautilus System.

§ The Nautilus System connects our Anaconda Gathering System and Manta Ray Offshore Gathering System to our Neptune natural gas processing plant located in south Louisiana.

§ The Nemo Gathering System gathers natural gas from producing fields located in the Green Canyon area of the Gulf of Mexico for delivery to an interconnect with our Manta Ray Offshore Gathering System.

§ The VESCO Gathering System gathers natural gas from certain offshore developments for delivery to the Venice natural gas processing plant in south Louisiana.

The following table presents selected information regarding our offshore crude oil pipelines at February 1, 2013:

Description of Asset	Our Ownership Interest		Length (Miles)	Approximate Net Capacity (MBPD) (1)
Offshore crude oil pipelines:				
Cameron Highway Oil Pipeline	50.0%	(2)	374	250
Shenzi Oil Pipeline	100.0%		83	230
Poseidon Oil Pipeline System	36.0%	(3)	367	155
Allegheny Oil Pipeline	100.0%		40	140
Marco Polo Oil Pipeline	100.0%		37	120
Constitution Oil Pipeline	100.0%		67	80
Typhoon Oil Pipeline	100.0%		17	80
Tarantula Oil Pipeline	100.0%		4	30
Total miles			989	

(1) Amounts presented are net to our ownership interest.
(2) Our ownership interest in the Cameron Highway Oil Pipeline is held indirectly through our equity method investment in Cameron Highway Oil Pipeline Company ("Cameron Highway").
(3) Our ownership interest in the Poseidon Oil Pipeline System is held indirectly through our equity method investment in Poseidon Oil Pipeline Company, L.L.C. ("Poseidon").

On a weighted-average basis, aggregate utilization rates for our offshore crude oil pipelines were approximately 27.7%, 25.7% and 29.5% during the years ended December 31, 2012, 2011 and 2010, respectively.

The following information describes each of our principal offshore crude oil pipelines, all of which we operate.

§ The Cameron Highway Oil Pipeline transports crude oil production from deepwater areas of the Gulf of Mexico, primarily the Green Canyon area, for delivery to refineries and terminals in southeast Texas. This system includes two pipeline junction platforms.

§ The Shenzi Oil Pipeline gathers crude oil production from the Shenzi production field located in the Green Canyon area of the Gulf of Mexico for delivery to both our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

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§ The Poseidon Oil Pipeline System transports crude oil production from the outer continental shelf and deepwater areas of the Gulf of Mexico offshore Louisiana to onshore facilities in south Louisiana. This system includes one pipeline junction platform.

§ The Allegheny Oil Pipeline connects the Allegheny and South Timbalier 316 platforms in the Green Canyon area of the Gulf of Mexico with our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The Marco Polo Oil Pipeline transports crude oil from our Marco Polo oil platform to an interconnect with our Allegheny Oil Pipeline in Green Canyon Block 164.

§ The Constitution Oil Pipeline gathers crude oil from the Constitution, Caesar Tonga and Ticonderoga production fields located in the Green Canyon area of the Gulf of Mexico for delivery to either our Cameron Highway Oil Pipeline or Poseidon Oil Pipeline System.

In January 2012, we executed transportation agreements with six Gulf of Mexico producers that will support construction of a 149-mile crude oil gathering pipeline serving the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The pipeline will be constructed and owned by Southeast Keathley Canyon Pipeline Company, L.L.C. ("SEKCO"), a 50/50 joint venture owned by us and Genesis Energy, L.P. We will serve as construction manager and operator of the new deepwater crude oil pipeline (the "SEKCO Oil Pipeline"), which is expected to have a capacity of 115 MBPD. The SEKCO Oil Pipeline is expected to begin service by mid-2014.

Offshore hub platforms. Offshore hub platforms are important components of our pipeline operations in the Gulf of Mexico. These platforms are typically used to interconnect the offshore pipeline network; provide an efficient means to perform pipeline maintenance; locate compression, separation and production handling equipment and similar assets; and conduct drilling operations during the initial development phase of an oil and natural gas property.

The results of operations from offshore platform services are primarily dependent upon the level of demand fees and/or commodity charges billable to customers. Demand fees are similar to firm capacity reservation agreements for a pipeline in that they are charged to a customer regardless of the volume the customer actually delivers to the platform. Revenue from commodity charges is based on a fee per unit of volume delivered to the platform (typically per MMcf of natural gas or per barrel of crude oil) multiplied by the total volume of each product delivered. Contracts for platform services often include both demand fees and commodity charges, but demand fees generally expire after a contractually fixed period of time and in some instances may be subject to cancellation by customers.

The following table presents selected information regarding our offshore hub platforms at February 1, 2013:

Description of Asset	Our Ownership Interest		Water Depth (Feet)	Approximate Net Capacity (1) Natural Gas (MMcf/d)	Crude Oil (MBPD)
Offshore hub platforms:					
Independence Hub	80.0%	(2)	8,000	800	N/A
Marco Polo	50.0%	(3)	4,300	150	60
Viosca Knoll 817	100.0%		671	145	5
Garden Banks 72	50.0%	(4)	518	113	18
East Cameron 373	100.0%		441	195	3
Falcon Nest	100.0%		389	400	3

(1) Amounts presented are net to our ownership interest.
(2) We own an 80% consolidated interest in the Independence Hub platform through our majority owned subsidiary, Independence Hub, LLC.
(3) Our ownership interest in the Marco Polo platform is held indirectly through our equity method investment in Deepwater Gateway, L.L.C. ("Deepwater Gateway").
(4) We proportionately consolidate our undivided interest in the Garden Banks 72 platform.

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In addition to our offshore hub platforms, we also own or indirectly own, through our equity method investments, 13 pipeline junction and service platforms. We operate 12 of the pipeline junction and service platforms. Unlike hub platforms, pipeline junction and service platforms do not have processing capacity.

With respect to natural gas processing capacity, the utilization rates (on a weighted-average basis) of our offshore hub platforms were approximately 16.2%, 22.5% and 28.5% during the years ended December 31, 2012, 2011 and 2010, respectively. With respect to crude oil processing capacity, the utilization rates (on a weighted-average basis) of our offshore platforms were approximately 18.9%, 19.3% and 19.2% during the years ended December 31, 2012, 2011 and 2010, respectively.

The following information describes each of our principal Gulf of Mexico offshore hub platforms. We operate these platforms with the exception of the Independence Hub and Marco Polo platforms.

§ The Independence Hub platform is located in Mississippi Canyon Block 920. This platform processes natural gas gathered from deepwater production fields in the Atwater Valley, DeSoto Canyon, Lloyd Ridge and Mississippi Canyon areas of the Gulf of Mexico.

Producers connected to our Independence Hub platform paid us $54.6 million of demand fees annually for five years beginning in March 2007 until that period expired in March 2012. We continue to receive revenues related to commodity charges from the producers.

§ The Marco Polo platform, which is located in Green Canyon Block 608, processes crude oil and natural gas from production fields located in the South Green Canyon area of the Gulf of Mexico.

§ The Viosca Knoll 817 platform is centrally located on our Viosca Knoll Gathering System. This platform primarily serves as a base for gathering deepwater production in the Viosca Knoll area, including the Ram Powell development.

§ The Garden Banks 72 platform serves as a base for gathering deepwater production from the Garden Banks area of the Gulf of Mexico. This platform also serves as a junction platform for our Cameron Highway Oil Pipeline and Poseidon Oil Pipeline System.

§ The East Cameron 373 platform processes production from the Garden Banks and East Cameron areas of the Gulf of Mexico.

§ The Falcon Nest platform, which is located in the Mustang Island East area of the Gulf of Mexico, processes natural gas from the Falcon field.

Seasonality. Our offshore operations exhibit little to no effects of seasonality; however, they may be affected by weather events such as hurricanes and tropical storms in the Gulf of Mexico, which generally arise during the summer and fall months. See Note 19 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding weather-related risks and insurance matters.

Competition. Within their respective market areas, our offshore pipelines compete with other offshore pipelines primarily on the basis of fees charged, available throughput capacity, connections to downstream markets and proximity and access to existing reserves.

Petrochemical & Refined Products Services

Our Petrochemical & Refined Products Services business segment includes (i) propylene fractionation and related operations; (ii) a butane isomerization facility and related pipeline system; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines and related marketing activities; and (v) marine transportation and other services.

Propylene fractionation and related operations. Our propylene fractionation and related operations consist of seven propylene fractionation plants, pipeline systems aggregating approximately 680 miles in length, and related petrochemical marketing activities. This business includes an export facility and associated above-ground polymer grade propylene storage spheres located in Seabrook, Texas.

In general, propylene fractionation plants separate refinery grade propylene, which is a mixture of propane and propylene, into either polymer grade propylene or chemical grade propylene along with by-products of propane and mixed butane. Polymer grade and chemical grade propylene can also be produced as a by-product of ethylene production. The demand for polymer grade propylene primarily relates to the manufacture of polypropylene, which has a variety of end uses including packaging film, fiber for carpets and upholstery and molded plastic parts for appliances and automotive, houseware and medical products. Chemical grade propylene is a basic petrochemical used in the manufacturing of plastics, synthetic fibers and foams.

The results of operations from propylene fractionation are generally dependent upon toll processing arrangements with customers and our petrochemical marketing activities. Toll processing arrangements typically include a base processing fee per gallon (or other unit of measurement) subject to adjustment for changes in power, fuel and labor costs, which are the primary costs of propylene fractionation. The results of operations from our petrochemical pipelines are primarily dependent upon the volume of products transported and the level of fees charged to shippers. Transportation fees are based on contractual arrangements and may include deficiency fee provisions whereby the customer pays us a fee if certain volume thresholds are not met over a contractual term.

Our petrochemical marketing activities purchase refinery grade propylene on the open market for fractionation in our plants and sell the resulting products at market-based prices. The selling price of such products may include pricing differentials for such factors as delivery location. The results of operations from our petrochemical marketing activities are primarily dependent upon the difference, or spread, between the sales prices of the products and associated purchase and other costs, including those costs attributable to the use of our other assets. As part of our petrochemical marketing activities, we have several long-term refinery grade propylene purchase and polymer grade propylene sales agreements. To limit the exposure of our petrochemical marketing activities to commodity price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

The following table presents selected information regarding our propylene fractionation facilities at February 1, 2013:

Description of Asset	Location(s)	Our Ownership Interest		Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)
Propylene fractionation facilities:					
Mont Belvieu (six units)	Texas	Various	(1)	73	87
BRPC (one unit)	Louisiana	30.0%	(2)	7	23
Total capacity				80	110

(1) We proportionately consolidate our 66.7% undivided interest in three of the Mont Belvieu propylene fractionators, which have an aggregate 41 MBPD of total plant capacity. The remaining three propylene fractionators at our Mont Belvieu facility are wholly owned.
(2) Our ownership interest in the BRPC facility is held indirectly through our equity method investment in Baton Rouge Propylene Concentrator LLC ("BRPC").

We produce polymer grade propylene at our Mont Belvieu, Texas propylene fractionation facility and chemical grade propylene at our BRPC facility located in Baton Rouge, Louisiana. The primary purpose of the BRPC unit is to fractionate refinery grade propylene produced by an affiliate of Exxon Mobil Corporation into chemical grade propylene. The polymer grade propylene produced by our Mont Belvieu facility is primarily for the benefit of our tolling customers and used in our petrochemical marketing activities to service long-term third party contracts. On a weighted-average basis, aggregate utilization rates of our propylene fractionation facilities were approximately 87.9%, 90.2% and 95.3% during the years ended December 31, 2012, 2011 and 2010, respectively. As noted previously, this business includes an export facility and above-ground polymer grade propylene storage spheres. This facility, which is located on the Houston Ship Channel in Seabrook, Texas, can load vessels at rates up to 5,000 barrels per hour.

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The following table presents selected information regarding our petrochemical pipelines at February 1, 2013:

Description of Asset	Location(s)	Ownership Interest		Length (Miles)
Petrochemical pipelines:				
Lou-Tex and Sabine Propylene	Texas, Louisiana	100.0%		287
Texas City RGP Gathering System	Texas	100.0%		164
North Dean Pipeline System	Texas	100.0%		149
Propylene Splitter PGP Distribution System	Texas	100.0%		33
Lake Charles PGP Pipeline	Louisiana	50.0%	(1)	26
La Porte PGP Pipeline	Texas	50.0%	(2)	17
Total miles				676

(1) We proportionately consolidate our undivided interest in the Lake Charles PGP Pipeline.
(2) Our ownership interest in the La Porte PGP Pipeline is held indirectly through our equity method investments in La Porte Pipeline Company, L.P. and La Porte Pipeline GP, L.L.C.

The Lou-Tex Propylene pipeline is used to transport chemical grade propylene from Sorrento, Louisiana to Mont Belvieu, Texas. The Sabine pipeline is used to transport polymer grade propylene from Port Arthur, Texas to a third party pipeline interconnect located in Cameron Parish, Louisiana. The North Dean Pipeline System transports refinery grade propylene from Mont Belvieu, Texas, to Point Comfort, Texas. The remainder of our petrochemical pipelines primarily transport refinery grade propylene or polymer grade propylene for customers in southeast Texas and southwest Louisiana.

The maximum number of barrels that our petrochemical pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our petrochemical pipelines vary according to the particular operating conditions that exist at any given time. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 117 MBPD, 117 MBPD and 141 MBPD during the years ended December 31, 2012, 2011, and 2010, respectively.

In June 2012, we announced plans to build one of the world's largest propane dehydrogenation ("PDH") units, with capacity to produce up to 1.65 billion pounds per year, which equates to approximately 750 thousand metric tons per year or 25 MBPD, of polymer grade propylene. The PDH facility is expected to consume up to 35 MBPD of propane as feedstock and be located in southeast Texas along the Gulf Coast. The new facility will be integrated with our existing propylene fractionation facilities, which will provide operational reliability and flexibility for both the PDH facility and the fractionation facilities. The PDH facility will also be integrated with our polymer grade propylene storage facilities, pipeline system and export terminal. The PDH facility, which is supported by long-term, fee-based contracts, is expected to begin commercial operations during the third quarter of 2015. We are in discussions with additional customers that could lead to the development of additional PDH capacity.

Butane isomerization facility and related pipeline system. Our butane isomerization business includes three butamer reactor units and eight associated deisobutanizer units located in Mont Belvieu, Texas, which comprise the largest commercial isomerization facility in the U.S. In addition, this business includes a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas. We own and operate these assets.

Our commercial isomerization units convert normal butane into mixed butane, which is subsequently fractionated into isobutane, high-purity isobutane and residual normal butane. The primary uses of isobutane are for the production of propylene oxide, isooctane, isobutylene and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for isobutane and high-purity isobutane in excess of the isobutane produced through the process of NGL fractionation and refinery operations.

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The results of operation of this business are generally dependent upon the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers. These processing arrangements typically include a base-processing fee per gallon (or other unit of measurement) subject to adjustment for changes in power, fuel and labor costs, which are the primary costs of isomerization. Our isomerization facility provides processing services to meet the needs of third party customers and our other businesses, including our NGL marketing activities and octane enhancement production facility. Our isomerization business also generates revenues from the sale of natural gasoline created as a by-product of the isomerization process.

The processing capacity of our isomerization facility is 116 MBPD. On a weighted-average basis, utilization rates for this facility were approximately 81.9%, 87.1% and 76.7% during the years ended December 31, 2012, 2011 and 2010, respectively.

Octane enhancement and high purity isobutylene production facilities. We own and operate an octane enhancement production facility located in Mont Belvieu, Texas that is designed to produce isooctane, isobutylene and methyl tertiary butyl ether ("MTBE"). The products produced by this facility are used in reformulated motor gasoline blends to increase octane values. The high-purity isobutane feedstocks consumed in the production of these products are supplied by our isomerization units.

The results of operations of this business are dependent upon the sale and delivery of products produced. In general, we sell our octane enhancement products at market-based prices. We attempt to mitigate the price risk associated with these products by entering into certain commodity derivative instruments. To the extent that we produce MTBE, it is sold into the export market. The production capacity of our octane enhancement facility is 12 MBPD of isooctane or 15.5 MBPD of MTBE. On a weighted-average basis, utilization rates for our octane enhancement facility were approximately 71%, 77.4% and 71% during the years ended December 31, 2012, 2011 and 2010, respectively.

We also own a facility located on the Houston Ship Channel that produces up to 4 MBPD of high purity isobutylene ("HPIB"). The primary feedstock for this plant, an isobutane/isobutylene mix, is produced by our Mont Belvieu octane enhancement facility. HPIB is used in the formulation of polyisobutylene, which is used in the manufacture of lubricants and rubber. The results of operations of this business are dependent upon the sale and delivery of products produced. In general, we sell HPIB at market-based prices. We acquired our HPIB facility in November 2010. On a weighted-average basis, utilization rates for this facility were 40% and 31.5% for the years ended December 31, 2012 and 2011, respectively.

Refined products pipelines and related marketing activities. Refined products pipelines and related activities include our TE Products Pipeline, an investment in Centennial Pipeline LLC ("Centennial"), and related storage, terminaling and marketing activities. The TE Products Pipeline transports refined petroleum products and NGLs such as propane and normal butane, from the Texas Gulf Coast to Midwest and northeast U.S. markets. The refined petroleum products (or "refined products") transported by this pipeline system are produced by refineries and include gasoline, diesel fuel, aviation fuel, kerosene, distillates, heating oil and blend stocks such as raffinate and naphtha. The Centennial Pipeline intersects our TE Products Pipeline near Creal Springs, Illinois, and effectively loops the TE Products Pipeline between Beaumont, Texas and south Illinois. There are also six refined products truck terminals and 13 storage terminals located along the TE Products Pipeline. In addition, we have three refined products terminals located along waterways in Mississippi, Alabama and Texas.

The results of operations from our refined products pipelines are primarily dependent upon the volume of products transported and the level of fees charged to shippers. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC. The results of our storage and terminal assets are primarily dependent on the volume and associated fees charged to customers.

Our refined products marketing activities generate revenues from the sale and delivery of refined products obtained on the open market. The results of operations from our refined products marketing activities are primarily dependent upon the difference, or spread, between product sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, we sell our refined products at market-based prices, which may include pricing differentials for such factors as delivery location. We also use derivative

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instruments to mitigate our exposure to commodity price risks associated with our refined products marketing activities.

The following table presents selected information regarding our refined products pipelines and related terminal and storage assets at February 1, 2013:

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Net Usable Storage Capacity (MMBbls)
Refined products pipelines and terminals:				
TE Products Pipeline (1,2)	Texas to Midwest and Northeast U.S.	100.0%	4,381	18.4
Centennial Pipeline (2)	Texas to central Illinois	50.0% (3)	795	1.2
Other terminals (4)	Alabama, Mississippi, Texas	100.0%	n/a	1.2
Total			5,176	20.8

(1) In addition to 18.4 MMBbls of refined products usable storage capacity, we have 4.9 MMBbls of NGL usable storage capacity that is used to support operations on our TE Products Pipeline. Our NGL storage and terminal assets are accounted for under our NGL Pipelines & Services business segment.
(2) Interstate and intrastate transportation services provided by the TE Products Pipeline and interstate transportation services provided by the Centennial Pipeline are regulated by governmental agencies.
(3) Our ownership interest in the Centennial Pipeline is held indirectly through our equity method investment in Centennial.
(4) Includes product distribution and marketing terminals located in Aberdeen, Mississippi and Boligee, Alabama having a usable storage capacity of 0.1 MMBbls and 0.5 MMBbls, respectively, and a storage terminal located in Pasadena, Texas having a usable storage capacity of 0.6 MMBbls.

The maximum number of barrels that our refined products pipelines can transport per day depends upon the operating balance achieved at a given point in time between various segments of the systems. Since the operating balance is dependent upon the mix of products to be shipped and demand levels at various delivery points, the exact capacities of our liquids pipelines vary according to the particular operating conditions that exist at any given time. We measure the utilization rates of such pipelines in terms of net throughput, which is based on our ownership interest. Aggregate net throughput volumes by product type for the TE Products Pipeline and Centennial Pipeline were as follows for the periods presented:

	For Year Ended December 31,		
	2012	2011	2010
Refined products transportation (MBPD)	383	429	511
Petrochemical transportation (MBPD)	101	121	122
NGL transportation (MBPD)	66	92	101

As a result of increased refinery production in the Midwest and Northeast U.S. markets served by our refined products pipelines along with lower overall demand for refined products in these regions, demand to transport refined products from the Gulf Coast to these markets has decreased. As discussed below, we are in the process of constructing new pipeline systems that will utilize portions of these refined products pipelines in providing a different service.

As noted previously, these pipelines are subject to regulation. See "Regulation" within this Part I, Item 1 and 2 discussion for information regarding the general effects of governmental oversight on our liquids pipelines, including tariffs charged for transportation services.

The following information describes each of our principal refined products pipelines. With the exception of the Centennial Pipeline, we operate our refined products pipelines and associated terminal facilities.

§ The TE Products Pipeline is a 4,381-mile pipeline system comprised of 4,063 miles of interstate pipelines and 318 miles of intrastate Texas pipelines. Refined products and NGLs are transported from the upper Texas Gulf Coast through two parallel pipelines that extend to Seymour, Indiana. From Seymour, segments of the TE Products Pipeline extend to the Chicago, Illinois; Lima, Ohio; Selkirk, New York; and Philadelphia (Sinking Spring), Pennsylvania areas. The TE Products Pipeline east of Todhunter, Ohio is

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primarily dedicated to NGL transportation services. Products are delivered to various locations along the system including to terminals owned either by us or third parties and to various connecting pipelines.

In January 2012, we announced the development of our ATEX Express long-haul ethane pipeline. This project will utilize a combination of new and existing infrastructure. The southern portion of ATEX Express would utilize one of the two parallel pipelines of our existing TE Products Pipeline, which would be transferred to ATEX and reversed to accommodate southbound delivery of ethane to the U.S. Gulf Coast. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014. As portions of the existing TE Products Pipeline are repurposed and begin commercial operations (e.g., the pipeline segments transferred to ATEX Express), the affected assets will be reclassified to the appropriate business segment (e.g., NGL Pipelines & Services) on a prospective basis.

§ The Centennial Pipeline is a refined products pipeline system that extends from Texas to Illinois. The Centennial Pipeline extends from an origination facility located on our TE Products Pipeline in Beaumont, Texas, to Bourbon, Illinois. Centennial owns a refined products storage terminal located near Creal Springs, Illinois with a gross storage capacity of 2.3 MMBbls.

Marine transportation and other services. Our marine transportation business consists of tow boats and tank barges that are used to transport refined products, crude oil, asphalt, condensate, heavy fuel oil, liquefied petroleum gas and other petroleum products along key inland and intracoastal U.S. waterways. The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. We refer to the combination of the power source and freight capacity as a tow. Our inland tows generally consist of one tow boat paired with up to four tank barges, depending upon the horsepower of the tow boat, location, waterway conditions, customer requirements and prudent operational considerations. Our offshore tows generally consist of one tow boat and one ocean-certified tank barge.

Our marine transportation assets service refinery and storage terminal customers along the Mississippi River, the intracoastal waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. We own a shipyard and repair facility located in Houma, Louisiana and marine fleeting facilities in Bourg, Louisiana and Channelview, Texas. The results of operations of our marine transportation business are generally dependent upon the level of fees charged to transport cargo. These transportation services are typically provided under term contracts (also referred to as affreightment contracts), which are agreements with specific customers to transport cargo from within designated operating areas at set day rates or a set fee per cargo movement.

Our marine transportation business is subject to regulation by the U.S. Department of Transportation ("DOT"), Department of Homeland Security, Commerce Department and the U.S. Coast Guard ("USCG") and federal and state laws.

The following table presents selected information regarding our marine transportation assets at February 1, 2013:

Class of Equipment	Number in Class	Capacity/ Horsepower (as indicated by sign) (1)
Inland marine transportation assets:		
Barges	19	< 25,000 bbls
Barges	104	> 25,000 bbls
Tow boats	37	< 2,000 hp
Tow boats	21	≥ 2,000 hp
Offshore marine transportation assets:		
Ocean-certified tank barges	8	≥ 20,000 bbls
Tow boats	3	< 2,000 hp
Tow boats	3	> 2,000 hp

(1) As used in this table, references to "bbls" means barrels and "hp" means horsepower.

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Our fleet of marine vessels operated at an average utilization rate of 90.9%, 91.8% and 91.9% during the years ended December 31, 2012, 2011 and 2010, respectively.

Seasonality. Overall, the propylene fractionation business exhibits little seasonality. Our isomerization operations experience slightly higher levels of demand in the spring and summer months due to increased demand for isobutane-based fuel additives used in the production of motor gasoline. Likewise, octane additive prices have been stronger from April to September each year when motor gasoline demand increases in connection with the summer driving season.

Our refined products pipelines and related activities exhibit seasonality based upon the mix of products delivered and the weather and economic conditions in the geographic areas being served. Refined products volumes are generally higher during the second and third quarters of each year because of greater demand for motor gasoline during the spring and summer driving seasons. NGL transportation volumes on the TE Products Pipeline are generally higher from October through March due to higher demand for propane (for residential heating) and normal butane (for blending in motor gasoline).

Our marine transportation business exhibits some seasonal variation. Demand for motor gasoline and asphalt is generally stronger in the spring and summer months due to the summer driving season and when weather allows for more efficient road construction. Weather events, such as hurricanes and tropical storms in the Gulf of Mexico, can adversely impact both the offshore and inland businesses. Generally during the winter months, cold weather and ice can negatively impact the inland operations on the upper Mississippi and Illinois rivers.

Competition. We compete with numerous producers of polymer grade propylene, which include many of the major refiners and petrochemical companies located along the Gulf Coast. Generally, our propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, quality of customer service, logistics and location.

With respect to our isomerization operations, we compete primarily with facilities located in Kansas, Louisiana and New Mexico. Competitive factors affecting this business include the level of toll processing fees charged, the quality of isobutane that can be produced and access to pipeline and storage supporting infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

The TE Products Pipeline's most significant competitors are third party pipelines in the areas where it delivers products. Competition among common carrier pipelines is based primarily on transportation fees, quality of customer service and proximity to end users. Trucks, barges and railroads competitively deliver products into some of the areas served by our TE Products Pipeline and river terminals. The TE Products Pipeline faces competition from rail and pipeline movements of NGLs from Canada and waterborne imports into terminals located along the upper East Coast.

Our marine transportation business competes with other inland marine transportation companies as well as providers of other modes of transportation, such as rail tank cars, tractor-trailer tank trucks and, to a limited extent, pipelines. Competition within the marine transportation business is largely based on price.

Title to Properties

Our real property holdings fall into two basic categories: (i) parcels that we and our unconsolidated affiliates own in fee (e.g., we own the land upon which our Mont Belvieu NGL fractionators are constructed) and (ii) parcels in which our interests and those of our affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our affiliates have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to

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our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

Regulation

The following sections describe the general impact of regulation on our business. Additional information regarding regulatory risks is included under Part I, Item 1A of this annual report.

Interstate Pipelines

Liquids Pipelines. Certain of our NGL, crude oil and refined products pipelines (collectively referred to as "liquids pipelines") are interstate common carrier pipelines subject to regulation by the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992 ("Energy Policy Act"). The ICA prescribes that the interstate tariffs we charge must be just and reasonable and must not be unduly discriminatory or confer any undue preference upon any shipper. FERC regulations require that interstate liquids pipeline transportation rates and terms of service be filed with the FERC.

The ICA permits interested persons to challenge proposed new or changed rates or rules and authorizes the FERC to investigate such changes and to suspend their effectiveness for a period of up to seven months. If, upon completion of an investigation, the FERC finds that the new or changed rate is not in accordance with the ICA, it may require the carrier to refund the revenues together with interest in excess of the prior tariff. The FERC may also investigate, upon complaint or on its own motion, rates and related rules that are already in effect and may order a carrier to change them prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of its complaint.

The Energy Policy Act deems just and reasonable (i.e., deems "grandfathered") those liquids pipeline rates that (i) were in effect for the 12 months preceding enactment of the legislation and (ii) that had not been subject to complaint, protest or investigation. Some, but not all, of our interstate liquids pipeline rates are considered grandfathered under the Energy Policy Act. Certain other rates for our interstate liquids pipeline services are charged pursuant to a FERC-approved indexing methodology, which allows a pipeline to charge rates up to a prescribed ceiling that changes annually based on the year-to-year change in the Producer Price Index for Finished Goods ("PPI"). A rate increase within the indexed rate ceiling is presumed to be just and reasonable unless a protesting party can demonstrate that the rate increase is substantially in excess of the pipeline's operating costs. During the five-year period commencing July 1, 2006 and ending June 30, 2011, liquids pipelines charging indexed rates were permitted to adjust their indexed rate ceilings annually by the PPI plus 1.3%. During the five-year period commencing July 1, 2011 and ending June 30, 2016, liquids pipelines charging indexed rates are permitted to adjust their indexed rate ceilings annually by the PPI plus 2.65%.

As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, competitive market showings (i.e., "market-based rates") or agreements with all of the pipeline's shippers that the rate is acceptable. Our TE Products Pipeline has been granted permission by the FERC to utilize market-based rates for all of its refined products movements other than movements to the Little Rock, Arkansas; Jonesboro, Arkansas; and Arcadia, Louisiana destination markets, which are currently subject to the PPI. However, as discussed below, movements of refined products to these three destination markets are the subject of a pending market-based rate application filed by Enterprise TE Products Pipeline Company LLC ("Enterprise TEPPCO"), which is an indirect wholly owned subsidiary of EPO.

The Lou-Tex and Sabine Propylene pipelines are interstate common carrier pipelines regulated under the ICA by the Surface Transportation Board ("STB"). If the STB finds that a carrier's rates are not just and reasonable or are unduly discriminatory or preferential, it may prescribe a reasonable rate. In determining a reasonable rate, the STB will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier's revenue needs and the availability of other economic transportation alternatives.

The STB does not need to provide rate relief unless shippers lack effective competitive alternatives. If the STB determines that effective competitive alternatives are not available and a pipeline holds market power, then we may be required to show that our rates are reasonable.

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Due to the complexity of the ratemaking process, prescribed rate methodologies for obtaining approved regulated tariff rates may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting higher costs. Changes in the FERC's methodology for approving rates could adversely affect us. In addition, challenges to our tariff rates could be filed with the FERC and future decisions by the FERC in approving our regulated rates could adversely affect our cash flow. We believe the transportation rates currently charged by our interstate common carrier liquids pipelines are in accordance with the ICA. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines. The following paragraphs summarize the ratemaking process surrounding our significant regulated assets since January 2010.

Seaway Crude Pipeline System

In December 2011, we and Enbridge Inc., which together own Seaway, filed an application in FERC Docket No. OR12-4-000, seeking authority to charge market-based rates in connection with the planned reversal of the system. Specifically, the application sought authority to charge market-based rates for the transportation of crude oil at both its Cushing, Oklahoma origin and Gulf Coast area destination markets following completion of the pipeline's reversal project in June 2012. Protests were filed by several parties. In May 2012, FERC denied the application for market-based rates because the FERC did not believe the evidence presented was sufficient to allow a determination that the reversed system lacked market power in the contested origin and destination markets. In response, Enterprise and Enbridge Inc. filed a petition for review of the FERC's order in Case No. 12-1222 at the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit"). In June 2012, FERC, on its own accord, granted rehearing of its May 2012 order to reconsider the effect on Enterprise and Enbridge Inc.'s market-based rate application of a recent DC Circuit order involving a different pipeline. In July 2012, the DC Circuit issued an order holding Case No. 12-1222 in abeyance pending the rehearing order at FERC. An order on rehearing from FERC remains pending. We are unable to predict the outcome of this ongoing proceeding.

In April 2012, Seaway filed a tariff in FERC Docket No. IS12-226 establishing initial cost-of-service rates for the transportation of crude oil on the Seaway Pipeline from Cushing, Oklahoma to U.S. Gulf Coast destination markets. Protests were filed by various parties. In May 2012, FERC accepted and suspended the tariff subject to refund and conditions, and established hearing procedures. The hearing is currently scheduled to occur in March 2013, and an Initial Decision is expected in August 2013. We are unable to predict the outcome of this ongoing proceeding.

In December 2012, Seaway filed a petition for a declaratory order in FERC Docket No. OR13-10 requesting FERC affirm that its policy of honoring tariff rates agreed to by shippers signing contracts in a valid open season applies equally to Seaway's committed shippers. The issue arose due to FERC Staff testimony filed in Docket No. IS12-226 regarding Seaway's committed rates. A FERC order on the petition is pending. We are unable to predict the outcome of this ongoing proceeding.

TE Products Pipeline

In March 2011, Enterprise TEPPCO filed an application in FERC Docket No. OR11-6-000, seeking authorization to charge market-based rates for the interstate transportation of refined products to the following three delivery locations: Little Rock, Arkansas; Jonesboro, Arkansas; and Arcadia, Louisiana. Protests were filed in April 2011 by Lion Oil Company and Chevron Products Company. In October 2011, the FERC set Enterprise TEPPCO's application for hearing before an administrative law judge ("ALJ"). The hearing was held in August 2012. In December 2012, the ALJ issued an initial decision determining that Enterprise TEPPCO failed to meet its burden of showing that it lacks market power in the three relevant destination markets. A final FERC Order on the matter is still pending. We are unable to predict the ultimate outcome of this ongoing proceeding.

In early February 2012, Enterprise TEPPCO filed a tariff in FERC Docket No. IS12-160-000 establishing new cost-of-service rates for refined products and NGL movements. In mid-February 2012, Enterprise TEPPCO filed, in FERC Docket No. IS12-165, a revised tariff to correct and cancel by replacement one of the tariffs filed in Docket No. IS12-160-000. Both filings were protested. In March 2012, FERC rejected both tariff filings without prejudice subject to Enterprise TEPPCO refiling proposed tariffs with more information.

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In March 2012, Enterprise TE Products Pipeline Company LLC filed tariffs in FERC Docket No. IS12-203 to increase certain of its natural gas liquids and refined products rates on the TE Products Pipeline in order to recover its cost-of-service, as well as to change certain of its market-based rates due to competition in the relevant markets. The filing was protested. In April 2012, the FERC suspended the tariffs for the statutory maximum seven-month period and allowed them to take effect in November 2012, subject to refund and investigation. Informal settlement conferences were held in December 2012 and early 2013. The hearing schedule is currently suspended pending settlement discussions. We are unable to predict the outcome of this ongoing proceeding.

Mid-America Pipeline System and Seminole Pipeline

In October 2009, the FERC approved an uncontested settlement related to a Mid-America Pipeline Company, LLC ("Mid-America") and Seminole rate case before the FERC. The case primarily involved shipper protests of rate increases on Mid-America's Conway North pipeline in FERC Docket Nos. IS05-216-000, IS06-238-000 and IS09-364-000, and challenges to Seminole's interstate rates and certain joint rates between the Seminole Pipeline and Mid-America's Rocky Mountain pipeline in FERC Docket Nos. OR06-5-000 and IS06-520-000. The settlement agreement resolved all matters involving Mid-America's Conway North pipeline at issue in Docket Nos. IS05-216-000, IS06-238-000 and IS09-364-000. Pursuant to the settlement agreement, Mid-America filed new rates for certain propane movements on its Conway North pipeline, which took effect January 1, 2010. Mid-America also paid refunds to propane shippers, as provided by the settlement agreement. In March 2010, Mid-America filed a refund report with the FERC describing the refunds paid. The FERC accepted the refund report in July 2010.

The settlement agreement did not cover challenges to the Seminole Pipeline and Mid-America Rocky Mountain pipeline rates at issue in Docket Nos. OR06-5-000 and IS06-520-000. In February 2010, the FERC ruled on those issues. The FERC's order also clarified that Mid-America's transportation capacity allocation provisions were not subject to challenge but that the changes to Mid-America's rates contained in FERC Tariff No. 45 were properly at issue. In March 2010, Mid-America and Seminole submitted a compliance filing with the FERC that calculated rates consistent with the February 2010 order. Two parties protested the revised rates. The FERC has not ruled on those protests and we are unable to predict the outcome of this ongoing proceeding.

In September 2011, Mid-America filed a tariff in FERC Docket No. IS11-604-000, establishing new rates for interstate transportation on a pipeline segment that moves refined products from Coffeyville, Kansas to El Dorado, Kansas. Coffeyville Resources Refining & Marketing, LLC protested the rate filing. In October 2011, the FERC accepted the tariff subject to refund and hearing. The FERC held the hearing in abeyance pending required settlement judge procedures. In April 2012, Coffeyville Resources Refining & Marketing, LLC withdrew its protest after reaching an agreement with Mid-America that resolved all outstanding issues in the proceeding. In May 2012, the settlement judge procedures were terminated and the hearing deemed unnecessary.

In December 2011, Mid-America filed a tariff change in FERC Docket No. IS12-97-000, requiring shippers on the Coffeyville to El Dorado pipeline segment to provide certain information necessary to determine whether shippers' movements are in interstate or intrastate commerce. In January 2012, Coffeyville Resources Refining & Marketing, LLC protested the tariff filing. In January 2012, the FERC accepted the tariff change in FERC Docket No. IS12-97-000, subject to certain language modifications.

Dixie Pipeline

In January 2012, Dixie Pipeline Company LLC ("Dixie") filed a tariff in FERC Docket No. IS12-120 indicating that as of January 1, 2013, propane shippers will no longer be permitted to inject propane into refinery grade propylene batches as the refinery grade propylene moves past the propane shippers' origin points. Instead, propane shippers will be required to make arrangements for propane storage during those periods. Protests were filed by CITGO Petroleum Corporation, Targa Midstream Services LLC, Crosstex Energy Services, L.P., Crosstex NGL Marketing, L.P., and Crosstex Processing Services, LLC. ConocoPhillips Company and Dow Hydrocarbons and Resources LLC moved to intervene. In February 2012, the FERC rejected Dixie's tariff as premature, since the proposed change was not intended to take effect until January 1, 2013.

In March 2012, Dixie filed a tariff in FERC Docket No. IS12-214 to establish rates, rules and regulations for isobutane movements from Mont Belvieu, Texas to Anse La Butte and Breaux Bridge, Louisiana and for normal

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butane movements from Anse La Butte and Breaux Bridge, Louisiana to Mont Belvieu, Texas. The filing was protested. In April 2012, the FERC accepted and suspended the tariff subject to the outcome of a technical conference. The technical conference was held in May 2012. Dixie filed an amended tariff proposal and several parties withdrew their protests. In November 2012, the FERC found Dixie's amended proposal was a reasonable accommodation of the issues, and ordered Dixie to file tariffs in accordance with the order. Dixie filed the tariffs in November 2012 in Docket Nos. IS13-43 and IS13-44.

ATEX Express

In November 2012, Enterprise Liquids Pipeline LLC filed a petition for a declaratory order in FERC Docket No. OR13-7 requesting FERC approval of the rate structure and terms of service agreed to by committed shippers on the proposed ATEX Express pipeline and a proration policy for the new pipeline. FERC action was requested no later than February 1, 2013. We are unable to predict the outcome of this ongoing proceeding.

Natural Gas Pipelines. Our natural gas pipelines that provide services in interstate commerce are regulated by the FERC under the Natural Gas Act of 1938 ("NGA"). The NGA prescribes that the interstate tariffs we charge must be just and reasonable and not unduly discriminatory. We operate these interstate facilities pursuant to tariffs which set forth rates and terms and conditions of service. These tariffs must be filed with and approved by the FERC pursuant to its regulations and orders. Our tariff rates may be lowered on a prospective basis only by the FERC if it finds, on its own initiative or as a result of challenges to the rates by third parties, that they are unjust, unreasonable or otherwise unlawful. Unless the FERC grants specific authority to charge market-based rates, our rates are derived and charged based on a cost-of-service methodology.

The FERC's authority over companies that provide natural gas pipeline transportation or storage services in interstate commerce also extends to: (i) the construction and operation of certain new facilities; (ii) the acquisition, extension, disposition or abandonment of such facilities; (iii) the maintenance of accounts and records; (iv) the initiation, extension and termination of regulated services; and (v) various other matters. The FERC's rules require interstate pipelines and their affiliates to adhere to Standards of Conduct that, among other things, require that transportation and marketing employees function independently of each other. The Energy Policy Act of 2005 amended the NGA to add an anti-manipulation provision. Pursuant to that act, the FERC established rules prohibiting energy market manipulation. A violation of these rules may subject us to civil penalties, disgorgement of unjust profits, or appropriate non-monetary remedies imposed by the FERC. In addition, the Energy Policy Act of 2005 amended the NGA and the Natural Gas Policy Act of 1978 ("NGPA") to increase civil and criminal penalties for any violation of the NGA, NGPA and any rules, regulations or orders of the FERC up to $1 million per day per violation.

In February 2012, the FERC issued an order allowing a storm event surcharge to be added to the rate charged by HIOS for services if a qualifying storm occurs. A request for rehearing of the February 2012 order is pending with the FERC. We are unable to predict the outcome of this ongoing proceeding.

Offshore Pipelines. Our offshore natural gas gathering pipelines and crude oil pipeline systems are subject to federal regulation under the Outer Continental Shelf Lands Act ("OCSLA"), which requires that all pipelines operating on or across the outer continental shelf provide nondiscriminatory transportation service.

Intrastate Pipelines

Liquids Pipelines. Certain of our pipeline systems provide intrastate transportation services. These pipeline systems are subject to various state statutes and regulations. Although the applicable state statutes and regulations vary widely, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may challenge intrastate tariff rates and practices on our pipelines. Our intrastate liquids pipelines are subject to regulation in many states, including Alabama, Colorado, Illinois, Kansas, Louisiana, Minnesota, Mississippi, New Mexico, Oklahoma and Texas.

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Natural Gas Pipelines. Our intrastate natural gas pipelines are subject to regulation in many states, including Colorado, Louisiana, New Mexico, Texas and Wyoming. Certain of our intrastate natural gas pipelines are also subject to limited regulation by the FERC under the NGPA because they provide transportation and storage service pursuant to Section 311 of the NGPA and Part 284 of the FERC's regulations. Under Section 311 of the NGPA, an intrastate pipeline may transport gas on behalf of an interstate pipeline company or any local distribution company served by an interstate pipeline without becoming subject to the FERC's jurisdiction under the NGA. However, such a pipeline is required to provide these services on an open and nondiscriminatory basis, to post certain transactional information on its website, and to make certain rate and other filings and reports in compliance with the FERC's regulations. The rates for Section 311 services may be established by the FERC or the respective state agency, but such rates may not exceed a fair and equitable rate. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate natural gas transportation operations in Texas.

In September 2011, Acadian Gas LLC ("Acadian Gas") filed a petition in FERC Docket No. PR11-129-000, seeking approval for new rates for NGPA Section 311 service on its new Haynesville Extension pipeline. As part of the petition for rate approval, Acadian Gas also filed changes to the Statement of Operating Conditions to reflect the new service. One party protested the changes to the Statement of Operating Conditions, but not the proposed new rates, and the protest was partially withdrawn in February 2012. In late February 2012, the FERC issued an order extending the time for action on the filing. As of December 31, 2012, we are unable to predict the outcome of this ongoing proceeding.

Natural Gas Sales

We are engaged in natural gas marketing activities. The resale of natural gas in interstate commerce is subject to the FERC's jurisdiction. However, under current federal rules the price at which we sell natural gas is not regulated insofar as the interstate market is concerned and, for the most part, is not subject to state regulation. Our affiliates that engage in natural gas marketing may be considered marketing affiliates of certain of our interstate natural gas pipelines. The FERC's rules require pipelines and their marketing affiliates who sell natural gas in interstate commerce subject to the FERC's jurisdiction to adhere to standards of conduct that, among other things, require that their transportation and marketing employees function independently of each other. Pursuant to the Energy Policy Act of 2005, the FERC has also established rules prohibiting energy market manipulation. A violation of these rules by us or our employees or agents may subject us to civil penalties, suspension or loss of authorization to perform such sales, disgorgement of unjust profits or other appropriate non-monetary remedies imposed by the FERC. The Federal Trade Commission and the Commodity Futures Trading Commission also have issued rules and regulations prohibiting market manipulation.

The FERC is continually proposing and implementing new rules and regulations affecting segments of the natural gas industry. For example, the FERC has adopted market monitoring and annual reporting regulations which are applicable to many intrastate pipelines and other entities that are otherwise not subject to the FERC's NGA jurisdiction. In order to increase transparency in natural gas markets, the FERC also has established rules requiring the annual reporting of data regarding natural gas sales.

Marine Operations

Maritime Law. The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third party claims and property damages to vessels and facilities. Routine towing operations can also create risk of personal injury under the Jones Act and General Maritime Law, cargo claims involving the quality of a product and delivery, terminal claims, contractual claims and regulatory issues.

Jones Act. We are subject to the Jones Act and other federal laws that restrict maritime transportation (between U.S. departure and destination points) to vessels built and registered in the U.S. and owned and manned by U.S. citizens. We are responsible for monitoring the foreign ownership of our common units and other partnership interests. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign

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transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels.

In addition, the USCG and American Bureau of Shipping ("ABS") maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness. In certain circumstances, a Jones Act seaman can have dual employers under the borrowed servant doctrine.

Merchant Marine Act of 1936. The Merchant Marine Act of 1936 is a federal law that provides, upon proclamation by the U.S. President of a national emergency or a threat to the national security, the U.S. Secretary of Transportation (the "Transportation Secretary") the authority to requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our tow boats or barges were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, if one of our tow boats is requisitioned or purchased and its associated barge or barges are left idle, we would not be entitled to receive any compensation for lost revenues resulting from the idled equipment. Also, we would not be entitled to compensation for any consequential damages we suffer as a result of the requisition or purchase of any of our tow boats or barges.

Environmental and Safety Matters

The following sections describe the general impact of environmental and safety matters on our business. Additional information regarding environmental and safety risks are described under Part I, Item 1A of this annual report.

Our operations are subject to various environmental and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. These include, without limitation: the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"); the Resource Conservation and Recovery Act ("RCRA"); the Federal Clean Air Act ("CAA"); the Federal Water Pollution Control Act of 1972, renamed and amended as the Clean Water Act ("CWA"); the Oil Pollution Act of 1990 ("OPA"); the Federal Occupational Safety and Health Act, as amended ("OSHA"); the Emergency Planning and Community Right to Know Act; and comparable or analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals, with respect to air emissions, water quality, wastewater discharges and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

If a leak, spill or release of hazardous substances occurs at any facilities that we own, operate or otherwise use, or where we send materials for treatment or disposal, we could be held liable for all resulting liabilities, including investigation, remedial and clean-up costs. Likewise, we could be required to remove previously disposed waste products or remediate contaminated property, including situations where groundwater has been impacted. Any or all of these developments could have a material adverse effect on our financial position, results of operations and cash flows.

We believe our operations are in material compliance with applicable environmental and safety laws and regulations. In addition, we expect that compliance with existing environmental and safety laws and regulations will not have a material adverse effect on our financial position, results of operations and cash flows. Environmental and safety laws and regulations are subject to change. The trend in environmental regulation has been to place more restrictions and limitations on activities that may be perceived to impact the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. New or revised 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 financial position, results of operations and cash flows.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. See Part I, Item 3 of this annual report for additional information.

Air Emissions

Our operations are associated with emissions of air pollutants. As a result, we are subject to the CAA and comparable state laws and regulations including state implementation plans. These laws and regulations regulate emissions of air pollutants from various industrial sources, including certain of our facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in an increase in existing air emissions, obtain and strictly comply with the requirements of air permits containing various emission and operational limitations, or utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, and enforcement actions. We may be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

The Texas Commission on Environmental Quality is working to finalize its rules in connection with CAA Section 185 fee regulations, which will apply to our operations in the Houston area. It is expected that such fees will be imposed on businesses starting in 2014. We believe, however, that such fees and our other state and federal air emission obligations under the CAA and similar statutes will not have a material adverse effect on our operations, and the requirements are not expected to be any more burdensome to us than any other similarly situated company.

Climate Change Regulations

Responding to scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases, including gases associated with oil and gas production such as carbon dioxide, methane and nitrous oxide among others, may be contributing to a warming of the earth's atmosphere and other adverse environmental effects, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. The U.S. Environmental Protection Agency ("EPA") has also taken action under the CAA to regulate greenhouse gas emissions. In addition, some states, including states in which our facilities or operations are located, have taken or proposed legal measures to reduce emissions of greenhouse gases.

The U.S. Congress, including the current 113th Congress, has proposed numerous legislative measures for imposing restrictions or requiring emissions fees for greenhouse gases. However, to date, there have been no resulting federal regulations promulgated that specifically restrict greenhouse gas emissions, which has resulted in certain states and regional partnerships taking the initiative. While the state specific efforts seem less burdensome, any such legislation may have the potential to affect our business, customers or the energy sector in general.

On an international level, the U.S. has been involved in negotiations regarding greenhouse gas reductions under the United Nations Framework Convention on Climate Change ("UNFCCC"). Other nations have already agreed to regulate emissions of greenhouse gases, pursuant to the UNFCCC and a subsidiary agreement known as the "Kyoto Protocol," an international treaty pursuant to which participating countries agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. The U.S. is a party to the UNFCCC but did not ratify the Kyoto Protocol. Such negotiations have not thus far resulted in substantive changes that would affect domestic industrial sources in the U.S. and it is uncertain whether an international agreement will be reached or what the terms of any such agreement would be.

Following the U.S. Supreme Court's decision in Massachusetts, et al. v. EPA, 549 U.S. 497 (2007), finding that greenhouse gases fall within the CAA definition of "air pollutant," the EPA determined that greenhouse gases from certain sources "endanger" public health or welfare. As a result, the EPA has taken the position that existing CAA provisions require an assessment of greenhouse gas emissions within the permitting process for certain large new or modified stationary sources under the EPA's Prevention of Significant Deterioration ("PSD") and Title V

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permit programs beginning in 2011. Facilities triggering permit requirements may be required to reduce greenhouse gas emissions consistent with "best available control technology" standards if deemed to be cost-effective. Such changes will also affect state air permitting programs in states that administer the CAA under a delegation of authority, including states in which we have operations. Additionally, in November 2010, the EPA finalized rules expanding its Mandatory Greenhouse Gas Reporting Rule, originally promulgated in October 2009, to be applicable to the oil and natural gas industry. The expansion requires annual, on-site monitoring and additional inventory and reporting of greenhouse gas emissions and affects many of our existing operations and must be considered for future operations. Although subject to legal challenge, the EPA rules promulgated thus far are currently final and effective, and will remain so unless the regulations are overturned by a court ruling, or Congress adopts legislation altering the EPA's regulatory authority.

A number of states, individually or in regional cooperation, have also imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy, or use of fuels with lower carbon content. These initiatives include the following:

§ Ten states in the Northeast and Mid-Atlantic region signed a compact and have implemented rules to limit carbon dioxide emissions from power plants under the Regional Greenhouse Gas Initiative ("RGGI"), which requires electric generating facilities to purchase emissions allowances corresponding to their respective emissions under a cap-and-trade system. RGGI started its second compliance period (from 2012-2014) under the cap-and-trade program and is currently conducting a state by state evaluation of the efficiency, impacts and economic feasibility of the program.

§ The California Air Resources Board ("CARB") issued a series of rules under that state's Global Warming Solutions Act, including restrictions on greenhouse gas emissions from industrial sources and regulating the carbon content of fuels. A multi-year, comprehensive program to reduce greenhouse gas emissions was put into effect by the CARB in January 2012.

§ In November 2010, the New Mexico Environmental Improvement Board adopted new regulations pursuant to state law establishing a greenhouse gas cap-and-trade program to be implemented by the New Mexico Environment Department. However, the cap-and-trade program was repealed in February 2012.

There have also been several court cases implicating greenhouse gas emissions and climate change issues that could have established a regulatory precedent. First, in September 2009, the U.S. Court of Appeals for the Second Circuit issued its decision in Connecticut v. American Electric Power Co., 582 F.3d 309 (2d Cir. Sept. 21, 2009). With this case, the Second Circuit held that certain state and private plaintiffs could sue energy companies on the asserted basis that greenhouse gas emissions created a "public nuisance." However, in June 2011, the U.S. Supreme Court held that the CAA and EPA actions displace the right to seek abatement of emissions under federal common law but left open whether state law tort actions were pre-empted. Second, a three-judge panel of the U.S. Court of Appeals for the Fifth Circuit initially upheld claims in Comer v. Murphy Oil USA, 585 F.3d 855 (5th Cir. Oct. 16, 2009), by property owners who suffered casualty losses in Hurricane Katrina alleging that certain energy, fossil fuel and chemical industries emitted greenhouse gases that contributed to global warming and ultimately exacerbated property damage from the hurricane. The Fifth Circuit subsequently vacated the panel decision and, because of a procedural issue, was unable to review the merits of the claims. In May 2011, the case was refiled in the Southern District of Mississippi with a focus on state law causes of action. The U.S. District Court for the Southern District of Mississippi dismissed the case for lack of standing in March 2012. A similar case, Native Village of Kivalina v. ExxonMobil Corp., 663 F. Supp. 2d 863 (N.D. Cal. Sept. 30, 2009), dismissed similar claims for lack of subject matter jurisdiction, and this decision was appealed to the U.S. Court of Appeals for the Ninth Circuit where the case was dismissed. In September 2012, plaintiffs filed an appeal with the Ninth Circuit for a rehearing of the case. While these cases expose other significant emission sources of greenhouse gases to similar litigation risk, there seems to be limited support for this type of legal action.

These federal, regional and state measures generally apply to industrial sources, including facilities in the oil and gas sector, and could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities. These regulations could also adversely affect market demand or pricing for our products or products served by our midstream infrastructure, by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources. The potential increase in the costs of our operations could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions, or administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final regulations. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage.

Physical Impacts of Climate Change

There is considerable debate over global warming and the environmental effects of greenhouse gas emissions and associated consequences affecting global climate, oceans and ecosystems. As a commercial enterprise, we are not in a position to validate or repudiate the existence of global warming or various aspects of the scientific debate. However, if global warming is occurring, it could have an impact on our operations. For example, our facilities that are located in low lying areas such as the coastal regions of Louisiana and Texas may be at increased risk due to flooding, rising sea levels, or disruption of operations from more frequent and severe weather events. Facilities in areas with limited water availability may be impacted if droughts become more frequent or severe. Changes in climate or weather may hinder exploration and production activities or increase the cost of production of oil and gas resources and consequently affect the volume of hydrocarbon products entering our system. Changes in climate or weather may also affect consumer demand for energy or alter the overall energy mix. However, we are not in a position to predict the precise effects of global climate change. We are providing this disclosure based on publicly available information on the matter.

Water

The CWA and comparable state laws impose strict controls on the discharge of oil and its derivatives into regulated waters. The CWA provides penalties for any discharges of petroleum products in reportable quantities and imposes substantial potential liability for the costs of removing petroleum or other hazardous substances. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of a release of petroleum or its derivatives in navigable waters or into groundwater. Spill prevention control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent a petroleum tank release from impacting regulated waters. The EPA has also adopted regulations that require us to have permits in order to discharge certain storm water run-off. Storm water discharge permits may also be required by certain states in which we operate and may impose certain monitoring and other requirements. The CWA further prohibits discharges of dredged and fill material in wetlands and other waters of the U.S. unless authorized by an appropriately issued permit. We believe that our costs of compliance with these CWA requirements will not have a material adverse effect on our financial position, results of operations and cash flows.

The primary federal law for oil spill liability is the OPA, which addresses three principal areas of oil pollution: prevention, containment and clean-up and liability. The OPA applies to vessels, offshore platforms and onshore facilities, including terminals, pipelines and transfer facilities. In order to handle, store or transport oil above certain thresholds, shore facilities are required to file oil spill response plans with the USCG, the DOT's Office of Pipeline Safety ("OPS") or the EPA, as appropriate. Numerous states have enacted laws similar to the OPA. Under the OPA and similar state laws, responsible parties for a regulated facility from which oil is discharged may be liable for removal costs and natural resource damages. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Contamination resulting from spills or releases of petroleum products is an inherent risk within the petroleum pipeline industry. To the extent that groundwater contamination requiring remediation exists along our pipeline systems or other facilities as a result of past operations, we believe any such contamination could be controlled or remedied without having a material adverse effect on our financial position, results of operations and cash flows, but such costs are site specific and there is no assurance that the effect will not be material in the aggregate.

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Environmental groups have instituted lawsuits regarding certain nationwide permits issued by the Army Corps of Engineers. These permits allow for streamlined permitting of pipeline projects. If these lawsuits are successful, timelines for pipeline construction projects could be impacted in the future.

Solid Waste

In our normal operations, we generate hazardous and non-hazardous solid wastes that are subject to requirements of the federal RCRA and comparable state statutes, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous and solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our waste.

Endangered Species

The federal Endangered Species Act, as amended, and comparable state laws, may restrict activities that affect endangered and threatened species or their habitats. Some of our current or future planned facilities may be located in areas that are designated as a habitat for endangered or threatened species and, if so, may limit or impose increased costs on facility construction or operation. In addition, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Environmental Remediation

CERCLA, also known as "Superfund," imposes liability, often without regard to fault or the legality of the original act, on certain classes of persons who contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of a facility where a release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at a facility. Under CERCLA, responsible parties may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA and RCRA also authorize the EPA and, in some instances, third parties to take actions in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. In the course of our ordinary operations, our pipeline systems and other facilities generate wastes that may fall within CERCLA's definition of a "hazardous substance" or be subject to CERCLA and RCRA remediation requirements. It is possible that we could incur liability for remediation or reimbursement of remediation costs under CERCLA or RCRA for remediation at sites we currently own or operate, whether as a result of our or our predecessors' operations, at sites that we previously owned or operated, or at disposal facilities previously used by us, even if such disposal was legal at the time it was undertaken.

Pipeline Safety Matters

We are subject to regulation by the DOT under the Accountable Pipeline and Safety Partnership Act of 1996, sometimes referred to as the Hazardous Liquid Pipeline Safety Act ("HLPSA"), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. The HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to (i) comply with such regulations, (ii) permit access to and copying of records, (iii) file certain reports and (iv) provide information as required by the Transportation Secretary. In addition, our natural gas pipeline assets are subject to the DOT's OPS under the Natural Gas Pipeline Safety Act ("NGPSA"). We believe we are in material compliance with these DOT regulations.

We are also subject to the DOT regulation requiring qualification of pipeline personnel. The regulation requires pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities. The intent of this regulation is to ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error. The regulation establishes qualification requirements for individuals performing covered tasks. In addition, we are subject to the DOT regulation that requires pipeline operators to institute certain control room procedures. These procedures were implemented in October 2011 and we believe we are in material compliance with these DOT regulations.

In addition, we are subject to the DOT pipeline integrity management regulations in 49 CFR Parts 192 and 195, which specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCAs"). HCAs are defined to include populated areas, unusually sensitive environmental areas and commercially navigable waterways. The regulation requires the development and implementation of an integrity management program that utilizes internal pipeline inspection, pressure testing or other equally effective means to assess the integrity of HCA pipeline segments. The regulation also requires periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised by the assessment and analysis. In June 2008, the DOT extended its pipeline safety regulations, including integrity management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines within a one-half mile buffer zone around "unusually sensitive areas." In May 2011, the DOT amended the pipeline safety regulations to apply the regulations to rural low-stress hazardous liquid pipelines that are not covered by the regulations in 49 CFR Part 195. Therefore, effective October 1, 2011, the pipeline safety regulations apply to all small-diameter (less than 8 5/8 inches) rural low-stress pipelines located within a one-half mile buffer zone of an unusually sensitive area and to all rural low-stress pipelines of any diameter located outside such one-half mile buffer zones. We have identified our HCA pipeline segments and developed an appropriate integrity management program.

The DOT also issued an Advance Notice of Proposed Rulemaking in October 2010 in Docket No. PHMSA-2010-0229 in which it is considering whether to remove or modify regulatory exemptions that currently exist in the pipeline safety regulations for the gathering of hazardous liquids by pipelines in rural areas. The comment period for this notice ended in February 2011; however, we cannot predict the ultimate impact of the proposed changes on our operations at this time.

In January 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"). This act provides stronger oversight of the nation's pipelines, increases the penalties for violations of pipeline safety rules, and complements the DOT's other initiatives. The 2011 Pipeline Safety Act increases the maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm from $1 million to $2 million. In addition, this law established additional safety requirements for newly constructed pipelines. The law also improves pipeline transportation and safety by: (i) improving pipeline damage prevention measures and cracking down on third party pipeline damage; (ii) allowing the Transportation Secretary to require automatic and remote-controlled shut-off valves on new pipelines; (iii) requiring the Transportation Secretary to evaluate the effectiveness of expanding pipeline integrity management and leak detection requirements; (iv) improving the way the DOT and pipeline operators provide information to the public and emergency responders; and (v) reforming the process by which pipeline operators notify federal, state and local officials of pipeline accidents.

The American Petroleum Institute Standard 653 ("API 653") is an industry standard for the inspection, repair, alteration and reconstruction of existing storage tanks. API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Periodic tank maintenance requirements 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 storage tanks.

Risk Management Plans

We are subject to the EPA's Risk Management Plan regulations at certain facilities. These regulations are intended to work with the OSHA Process Safety Management ("PSM") regulations (see "—Other Safety Matters" below) to minimize the offsite consequences of catastrophic releases. The regulations require us to develop and implement a risk management program that includes a five-year accident history, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in material compliance with our risk management program.

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Other Safety Matters

Certain of our facilities are also subject to the requirements of the federal OSHA and comparable state statutes. We believe we are in material compliance with OSHA and state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures.

Certain of our facilities are subject to OSHA PSM regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves certain flammable liquid or gas. We believe we are in material compliance with the OSHA PSM regulations.

The OSHA hazard communication standard, the community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to federal, state and local governmental authorities and local citizens upon request. These laws and provisions of CERCLA require reporting of spills and releases of hazardous chemicals in certain situations.

Duncan and Holdings Mergers

Duncan Merger – September 2011

Duncan Energy Partners L.P. ("Duncan Energy Partners") was formed by Enterprise Products Partners in September 2006 and completed its initial public offering in February 2007 (NYSE: DEP). Duncan Energy Partners was under common control with Enterprise by affiliates of EPCO and its business purpose was to acquire, own and operate midstream energy assets. In April 2011, we, our general partner, EPD MergerCo LLC ("Duncan MergerCo," our wholly owned subsidiary), Duncan Energy Partners and DEP Holdings, LLC ("DEP GP," the general partner of Duncan Energy Partners) entered into a definitive merger agreement (the "Duncan Merger Agreement"). In September 2011, the Duncan Merger Agreement was approved by the unitholders of Duncan Energy Partners and the merger of Duncan MergerCo with and into Duncan Energy Partners and related transactions were completed, with Duncan Energy Partners surviving such merger as our wholly owned subsidiary (collectively, we refer to these transactions as the "Duncan Merger").

Each issued and outstanding common unit of Duncan Energy Partners was cancelled and converted into the right to receive our limited partner common units based on an exchange ratio of 1.01 Enterprise common units for each Duncan Energy Partners common unit. We issued 24,277,310 of our common units (net of fractional common units cashed out) to the former public unitholders of Duncan Energy Partners as consideration in the Duncan Merger. We did not issue any common units as merger consideration to our subsidiaries that owned limited partner interests in Duncan Energy Partners.

Since we historically consolidated Duncan Energy Partners for financial reporting purposes, the Duncan Merger did not change the basis of presentation of our historical financial statements.

Holdings Merger – November 2010

Enterprise GP Holdings L.P. ("Holdings") was formed in April 2005 and completed its initial public offering in August 2005 (NYSE: EPE). The business purpose of Holdings was to own general and limited partner interests of publicly traded partnerships engaged in the midstream energy industry. Among its investments, Holdings owned Enterprise's general partner and was under common control with Enterprise by affiliates of EPCO. In September 2010, Holdings, Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," our wholly owned subsidiary) entered into a merger agreement (the "Holdings Merger Agreement"). In November 2010, the Holdings Merger Agreement was approved by the unitholders of Holdings and the merger of Holdings with and into Holdings MergerCo and related transactions were completed, with Holdings MergerCo surviving such merger (collectively, we refer to these transactions as the "Holdings Merger"). Enterprise's membership interests in Holdings MergerCo were subsequently contributed to EPO. As a result of completing the Holdings Merger, Enterprise GP, which had previously been the general partner of Holdings ("Holdings GP"), became Enterprise's general partner.

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At the effective time of the Holdings Merger, each issued and outstanding unit representing limited partner interests in Holdings was cancelled and converted into the right to receive our common units based on an exchange ratio of 1.5 Enterprise common units for each Holdings unit. We issued an aggregate of 208,813,454 of our common units (net of fractional common units cashed out) as consideration in the Holdings Merger and, immediately after the merger, cancelled 21,563,177 of our common units previously owned by Holdings.

In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). The temporary distribution waiver remains in effect for five years following the closing date of the Holdings Merger. The number of Designated Units to which the temporary distribution waiver applies is as follows for distributions paid or to be paid, if any, during the following calendar years: 30,610,000 during 2011; 26,130,000 during 2012; 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015. For example, distributions paid to partners during calendar year 2012 excluded 26,130,000 Designated Units; however, distributions to be paid, if any, during calendar year 2013 would exclude 23,700,000 Designated Units.

As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). See Note 1 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding the basis of presentation of our general purpose financial statements. Such information is incorporated by reference into this Item 1 and 2 discussion.

Available Information

As a publicly traded partnership, we electronically file certain documents with the Securities and Exchange Commission ("SEC"). We file annual reports on Form 10-K; quarterly reports on Form 10-Q; and current reports on Form 8-K (as appropriate); along with any related amendments and supplements thereto. Occasionally, we may also file registration statements and related documents in connection with equity or debt offerings. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at (800) SEC-0330. In addition, the SEC maintains an Internet website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

We provide electronic access to our periodic and current reports on our Internet website, www.enterpriseproducts.com. These reports are available as soon as reasonably practicable after we electronically file such materials with, or furnish such materials to, the SEC. You may also contact our Investor Relations department at (866) 230-0745 for paper copies of these reports free of charge. We do not intend to incorporate the information on our website into this annual report.

Item 1A. Risk Factors.

An investment in our common units or debt securities involves certain risks. If any of the following key risks were to occur, it could have a material adverse effect on our financial position, results of operations and cash flows, as well as our ability to maintain or increase distribution levels. In any such circumstance and others described below, the trading price of our securities could decline and you could lose part or all of your investment.

Risks Relating to Our Business

Our standalone operating cash flow is derived primarily from cash distributions we receive from EPO.

On a standalone basis, Enterprise Products Partners L.P. is a holding company with no business operations and conducts all of its business through its wholly owned subsidiary, EPO. As a result, we depend upon the earnings and cash flows of EPO and its subsidiaries and joint ventures, and the distribution of that cash to us in order to meet our obligations and to allow us to make cash distributions to our partners.

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The amount of cash EPO and its subsidiaries and joint ventures can distribute principally depends upon the cash flow generated from their operations, which will fluctuate from quarter-to-quarter based on, among other things, the: (i) volume of hydrocarbon products transported on their gathering and transmission pipelines; (ii) throughput volumes in their processing and treating operations; (iii) fees charged and the margins realized for their various storage, terminaling, processing and transportation services; (iv) price of natural gas, crude oil and NGLs; (v) relationships among natural gas, crude oil and NGL prices, including differentials between regional markets; (vi) fluctuations in their working capital needs; (vii) level of their operating costs; (viii) prevailing economic conditions; and (ix) level of competition encountered by their businesses. In addition, the actual amount of cash EPO and its subsidiaries and joint ventures will have available for distribution will depend on factors such as: (i) the level of sustaining capital expenditures incurred; (ii) their cash outlays for expansion (or growth) capital projects and acquisitions; and (iii) their debt service requirements and restrictions included in the provisions of existing and future indebtedness, charter documents, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies, applicable to them. Because of these factors, we may not have sufficient available cash each quarter to continue paying distributions at our current levels.

Furthermore, the amount of cash we have available for distribution is not solely a function of profitability, which will be affected by non-cash items such as depreciation, amortization and provisions for asset impairments. Our cash flows are also impacted by borrowings under credit agreements and similar arrangements. As a result, we may be able to make cash distributions during periods when we record losses and may not be able to make cash distributions during periods when we record net income. An inability on our part to pay cash distributions to partners at our current levels or projected levels could have an adverse effect on our financial position, results of operations and cash flows.

Changes in demand for and production of hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows.

We operate predominantly in the midstream energy industry, which includes gathering, transporting, processing, fractionating and storing natural gas, NGLs, crude oil, petrochemical and refined products. As such, changes in the prices of hydrocarbon products and in the relative price levels among hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and the volumes of products for which we provide services. We may also incur credit and price risk to the extent counterparties do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, propylene, refined products and/or crude oil.

Historically, the price of natural gas has been extremely volatile, and we expect this volatility to continue. The New York Mercantile Exchange ("NYMEX") daily settlement price for natural gas for the prompt month contract ranged: in 2010, from a high of $6.01 per MMBtu to a low of $3.29 per MMBtu; in 2011, from a high of $4.85 per MMBtu to a low of $2.99 per MMBtu; and in 2012, from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu.

Generally, prices of hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of other uncontrollable factors, such as: (i) the level of domestic production and consumer product demand; (ii) the availability of imported oil and natural gas and actions taken by foreign oil and natural gas producing nations; (iii) the availability of transportation systems with adequate capacity; (iv) the availability of competitive fuels; (v) fluctuating and seasonal demand for oil, natural gas, NGLs and other hydrocarbon products; (vi) the impact of conservation efforts; (vii) governmental regulation and taxation of production; and (viii) prevailing economic conditions.

We are exposed to natural gas and NGL commodity price risk under certain of our natural gas processing and gathering and NGL fractionation contracts that provide for our fees to be calculated based on a regional natural gas or NGL price index or to be paid in-kind by taking title to natural gas or NGLs. A decrease in natural gas and NGL prices can result in lower margins from these contracts, which could have a material adverse effect on our financial position, results of operations and cash flows. Volatility in commodity prices may also have an impact on many of our customers, which in turn could have a negative impact on their ability to fulfill their obligations to us.

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The crude oil, natural gas and NGLs currently transported, gathered or processed at our facilities originate from existing domestic and international resource basins, which naturally deplete over time. To offset this natural decline, our facilities will need access to production from newly discovered properties. Many economic and business factors beyond our control can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low oil and natural gas prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. A decrease in exploration and development activities in the regions where our facilities and other energy logistic assets are located could result in a decrease in volumes to our natural gas processing plants, natural gas, crude oil and NGL pipelines, NGL fractionators and offshore platforms, which could have a material adverse effect on our financial position, results of operations and cash flows.

A decrease in demand for NGL products by the petrochemical, refining or heating industries could have a material adverse effect on our financial position, results of operations and cash flows.

Decreases in demand may be caused by prevailing economic conditions, reduced demand by consumers for the end products made with NGL products, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, government regulations affecting prices and production levels of natural gas, the content of motor gasoline, or other reasons. For example:

§ Ethane is primarily used in the petrochemical industry as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. If natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls (and, therefore, the demand for ethane decreases), where gas quality specifications would allow, it may be more profitable for natural gas producers to leave the ethane in a mixed natural gas stream to be burned as fuel than to extract it for sale as an ethylene feedstock.

§ The demand for propane as a heating fuel is significantly affected by weather conditions. Unusually warm winters could cause the demand for propane to decline significantly and could cause a significant decline in the volumes of propane that we transport.

§ A reduction in demand for motor gasoline additives may reduce demand for isobutane, which could adversely impact the price of isobutane and reduce our operating margin from selling isobutane.

§ Propylene is sold to petrochemical companies for a variety of uses, principally for the production of polypropylene. Propylene is subject to rapid and material price fluctuations. Any downturn in the domestic or international economy could cause reduced demand for, and an oversupply of propylene, which could cause a reduction in the volumes of propylene that we sell and transport.

We face competition from third parties in our midstream energy businesses.

Even if crude oil and natural gas reserves exist in the areas served by our assets, we may not be chosen by producers in these areas to gather, transport, process, fractionate, store or otherwise handle the hydrocarbons extracted. We compete with other companies, including producers of oil and natural gas, for any such production on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets.

Our refined products, NGL and marine transportation businesses may compete with other pipelines and marine transportation companies in the areas they serve. We also compete with railroads and third party trucking operations in certain of the areas we serve. Competitive pressures may adversely affect our tariff rates or volumes shipped. Also, substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business.

The crude oil gathering and marketing business can be characterized by thin operating margins and intense competition for supplies of crude oil at the wellhead. A decline in domestic crude oil production could intensify this competition among gatherers and marketers. Our crude oil transportation business competes with common carriers and proprietary pipelines owned and operated by major oil companies, large independent pipeline companies,

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financial institutions with trading platforms and other companies in the areas where such pipeline systems deliver crude oil.

In our natural gas gathering business, we encounter competition in obtaining contracts to gather natural gas supplies, particularly new supplies. Competition in natural gas gathering is based in large part on reputation, efficiency, system reliability, gathering system capacity and pricing arrangements. Our key competitors in the gas gathering segment include independent gas gatherers and major integrated energy companies. Alternate gathering facilities are available to producers we serve, and those producers may also elect to construct proprietary gas gathering systems.

A significant increase in competition in the midstream energy industry could have a material adverse effect on our financial position, results of operations and cash flows.

Our debt level may limit our future financial and operating flexibility.

As of December 31, 2012, we had $14.3 billion in principal amount of consolidated senior long-term debt outstanding, $1.53 billion in principal amount of junior subordinated debt outstanding and $346.6 million in short-term commercial paper notes outstanding. The amount of our future debt could have significant effects on our operations, including, among other things:

§ a substantial portion of our cash flow could be dedicated to the payment of principal and interest on our future debt and may not be available for other purposes, including the payment of distributions on our common units and capital expenditures;

§ credit rating agencies may take a negative view of our consolidated debt level;

§ covenants contained in our existing and future credit and debt agreements will require us to continue to meet financial tests that may adversely affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;

§ our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

§ we may be at a competitive disadvantage relative to similar companies that have less debt; and

§ we may be more vulnerable to adverse economic and industry conditions as a result of our significant debt level.

Our public debt indentures currently do not limit the amount of future indebtedness that we can incur, assume or guarantee. Although our credit agreements restrict our ability to incur additional debt above certain levels, any debt we may incur in compliance with these restrictions may still be substantial. For information regarding our long-term debt, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Our credit agreements and each of the indentures related to our public debt instruments include traditional financial covenants and other restrictions. For example, we are prohibited from making distributions to our partners if such distributions would cause an event of default or otherwise violate a covenant under our credit agreements. A breach of any of these restrictions by us could permit our lenders or noteholders, as applicable, to declare all amounts outstanding under these debt agreements to be immediately due and payable and, in the case of our credit agreements, to terminate all commitments to extend further credit.

Our ability to access capital markets to raise capital on favorable terms could be affected by our debt level, when such debt matures, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, we could experience an increase in our borrowing costs, difficulty assessing capital markets and/or a reduction in the market price of our securities. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions, or to refinance existing indebtedness. If

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we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term debt obligations or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected levels.

We may not be able to fully execute our growth strategy if we encounter illiquid capital markets or increased competition for investment opportunities.

Our growth strategy contemplates the development and acquisition of a wide range of midstream and other energy infrastructure assets while maintaining a strong balance sheet. This strategy includes constructing and acquiring additional assets and businesses that enhance our ability to compete effectively and to diversify our asset portfolio, thereby providing us with more stable cash flows. We consider and pursue potential joint ventures, standalone projects and other transactions that we believe may present opportunities to expand our business, increase our market position and realize operational synergies.

We will require substantial new capital to finance the future development and acquisition of assets and businesses. For example, for the year ended December 31, 2012, we spent $3.8 billion on growth capital projects, of which approximately $1.5 billion was for the Eagle Ford Shale projects and $644 million was for Mont Belvieu projects. Based on information currently available, we estimate our consolidated capital spending for 2013 will approximate $4.4 billion, which includes estimated expenditures of $4.0 billion for growth capital projects and $350 million for sustaining capital expenditures. Any limitations on our access to capital may impair our ability to execute this growth strategy. If our cost of debt or equity capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We also may not be able to raise the necessary funds on satisfactory terms, if at all.

Any future tightening of the credit markets may have a material adverse effect on us by, among other things, decreasing our ability to finance growth capital projects or business acquisitions on favorable terms and by the imposition of increasingly restrictive borrowing covenants. In addition, the distribution yields of any new equity we may issue may be higher than historical levels, making additional equity issuances more expensive.

We also may compete with third parties in the acquisition of energy infrastructure assets that complement our existing asset base. Increased competition for a limited pool of assets could result in our losing to other bidders more often than in the past or acquiring assets at less attractive prices. Either occurrence could limit our ability to fully execute our growth strategy. Our inability to execute our growth strategy may materially adversely affect our ability to maintain or pay higher cash distributions in the future.

Our variable-rate debt, including those fixed-rate debt obligations converted to variable-rate through the use of interest rate swaps, make us vulnerable to increases in interest rates, which could have a material adverse effect on our financial position, results of operation and cash flows.

As of December 31, 2012, we had $16.18 billion in total principal amount of consolidated debt outstanding. Of this amount, $150.0 million, or approximately 1%, was subject to variable interest rates due to the use of interest rate swaps to effectively convert long-term fixed-rate debt to variable rates.

At December 31, 2012, we had $1.2 billion, $1.15 billion, $1.3 billion, $750.0 million and $800.0 million of senior notes maturing in 2013, 2014, 2015, 2016 and 2017, respectively. In addition, any future principal amounts outstanding under our variable-rate $3.5 billion Multi-Year Revolving Credit Facility mature in 2016. We also had $346.6 million in principal amount of commercial paper notes outstanding at December 31, 2012 that matured in January 2013.

Should interest rates increase significantly, the amount of cash required to service our debt (including any future refinancing of our fixed-rate debt instruments) would increase. Additionally, from time to time, we may enter into additional interest rate swap arrangements, which could increase our exposure to variable interest rates. As a

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result, significant increases in interest rates could have a material adverse effect on our financial position, results of operations and cash flows.

An increase in interest rates may also cause a corresponding decline in demand for equity securities in general, and in particular, for yield-based equity securities such as our common units. A reduction in demand for our common units may cause their trading price to decline.

Our growth strategy may adversely affect our results of operations if we do not successfully integrate and manage the businesses that we acquire or if we substantially increase our indebtedness and contingent liabilities to make acquisitions.

Our growth strategy includes making accretive acquisitions. As a result, from time to time, we will evaluate and acquire assets and businesses that we believe complement our existing operations. We may be unable to successfully integrate and manage the businesses we acquire in the future. We may incur substantial expenses or encounter delays or other problems in connection with our growth strategy that could have a material adverse effect on our financial position, results of operations and cash flows. Moreover, acquisitions and business expansions involve numerous risks, such as:

§ difficulties in the assimilation of the operations, technologies, services and products of the acquired assets or businesses;

§ establishing the internal controls and procedures we are required to maintain under the Sarbanes-Oxley Act of 2002;

§ managing relationships with new joint venture partners with whom we have not previously partnered;

§ experiencing unforeseen operational interruptions or the loss of key employees, customers or suppliers;

§ inefficiencies and complexities that can arise because of unfamiliarity with new assets and the businesses associated with them, including with their markets; and

§ diversion of the attention of management and other personnel from day-to-day business to the development or acquisition of new businesses and other business opportunities.

If consummated, any acquisition or investment would also likely result in the incurrence of indebtedness and contingent liabilities and an increase in interest expense and depreciation, amortization and accretion expenses. As a result, our capitalization and results of operations may change significantly following a material acquisition. A substantial increase in our indebtedness and contingent liabilities could have a material adverse effect on our financial position, results of operations and cash flows. In addition, any anticipated benefits of a material acquisition, such as expected cost savings or other synergies, may not be fully realized, if at all.

Acquisitions that appear to increase our operating cash flows may nevertheless reduce our operating cash flows on a per unit basis.

Even if we make acquisitions that we believe will increase our operating cash flows, these acquisitions may ultimately result in a reduction of operating cash flow on a per unit basis, such as if our assumptions regarding a newly acquired asset or business did not materialize or unforeseen risks occurred. As a result, an acquisition initially deemed accretive based on information available at the time could turn out not to be. Examples of risks that could cause an acquisition to ultimately not be accretive include our inability to achieve anticipated operating and financial projections or to integrate an acquired business successfully, the assumption of unknown liabilities for which we become liable, and the loss of key employees or key customers. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will in making such decisions. As a result of the risks noted above, we may not realize the full benefits we expect from a material acquisition, which could have a material adverse effect on our financial position, results of operations and cash flows.

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Our actual construction, development and acquisition costs could materially exceed forecasted amounts.

We have announced and are engaged in multiple significant construction projects involving existing and new assets for which we have expended or will expend significant capital. These projects entail significant logistical, technological and staffing challenges. We may not be able to complete our projects at the costs we estimated at the time of each project's initiation or that we currently estimate. For example, material and labor costs associated with our past projects in the Rocky Mountains region increased over time due to factors such as higher transportation costs and the availability of construction personnel. Similarly, force majeure events such as hurricanes along the U.S. Gulf Coast may cause delays, shortages of skilled labor and additional expenses for these construction and development projects, such as were experienced with Hurricanes Gustav and Ike in 2008.

If capital expenditures materially exceed expected amounts, then our future cash flows could be reduced, which, in turn, could reduce the amount of cash we expect to have available for distribution. In addition, a material increase in project costs could result in decreased overall profitability of the newly constructed asset once it is placed into commercial service.

Our construction of new assets is subject to regulatory, environmental, political, legal and economic risks, which may result in delays, increased costs or decreased cash flows.

One of the ways we intend to grow our business is through the construction of new midstream energy infrastructure assets. The construction of new assets involves numerous operational, regulatory, environmental, political and legal risks beyond our control and may require the expenditure of significant amounts of capital. These potential risks include, among other things, the following:

§ we may be unable to complete construction projects on schedule or at the budgeted cost due to the unavailability of required construction personnel or materials, accidents, weather conditions or an inability to obtain necessary permits;

§ we will not receive any material increase in operating cash flows until the project is completed, even though we may have expended considerable funds during the construction phase, which may be prolonged;

§ we may construct facilities to capture anticipated future production growth in a region in which such growth does not materialize;

§ since we are not engaged in the exploration for and development of natural gas reserves, we may not have access to third party estimates of reserves in an area prior to our constructing facilities in the area. As a result, we may construct facilities in an area where the reserves are materially lower than we anticipate;

§ in those situations where we do rely on third party reserve estimates in making a decision to construct assets, these estimates may prove inaccurate;

§ the completion or success of our construction project may depend on the completion of a third party construction project (e.g., a downstream crude oil refinery expansion) that we do not control and that may be subject to numerous of its own potential risks, delays and complexities; and

§ we may be unable to obtain rights-of-way to construct additional pipelines or the cost to do so may be uneconomical.

A materialization of any of these risks could adversely affect our ability to achieve growth in the level of our cash flows or realize benefits from expansion opportunities or construction projects, which could impact the level of cash distributions we pay to partners.

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Privately held affiliates of EPCO (together with their respective subsidiaries) have pledged up to 62,500,000 of our common units as security under such affiliates' credit facilities. Upon an event of default under any of these credit facilities, a change in ownership of these units could ultimately result.

Privately held affiliates of EPCO (together with their respective subsidiaries) have pledged up to 62,500,000 of our common units that they own as security under such affiliates' credit facilities. These credit facilities contain customary and other events of default, including defaults by Enterprise and other affiliates of EPCO. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units. A development of this nature could affect the market price of our common units.

The credit and risk profile of owners of our general partner and their privately held affiliates could adversely affect our risk profile, which could increase our borrowing costs, hinder our ability to raise capital or impact future credit ratings.

The credit and business risk profiles of the owners of our general partner and their privately held affiliates may factor into the credit evaluations of our partnership. This is because the general partner can exercise significant influence over the business activities of our partnership, including its cash distribution policy, acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of owners of our general partner and their privately held affiliates, including the degree of their financial leverage and their dependence on cash flow from our partnership to service their indebtedness.

Affiliates of the entities controlling the owner of our general partner have significant indebtedness outstanding and are dependent principally on the cash distributions from their limited partner equity interests in us to service such indebtedness. Any distributions by us to such entities will be made only after satisfying our then current obligations to creditors.

Although we have taken certain steps in our organizational structure, financial reporting and contractual relationships to reflect the separateness of us and our general partner from the entities that control our general partner, our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of EPCO or the entities that control our general partner were viewed as substantially lower or more risky than ours. A development of this nature could affect the market price of our common units.

A natural disaster, catastrophe, terrorist attack or other event could result in severe personal injury, property damage and environmental damage, which could curtail our operations and have a material adverse effect on our financial position, results of operations and cash flows.

Some of our operations involve risks of personal injury, property damage and environmental damage, which could curtail our operations and otherwise materially adversely affect our cash flow. For example, natural gas facilities operate at high pressures, sometimes in excess of 1,100 pounds per square inch. We also operate crude oil and natural gas facilities located underwater in the Gulf of Mexico, which can involve complexities, such as extreme water pressure. In addition, our marine transportation business is subject to additional risks, including the possibility of marine accidents and spill events. From time to time, our octane enhancement facility may produce MTBE for export, which could expose us to additional risks from spill events. Virtually all of our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and/or earthquakes. The location of our assets and our customers' assets in the U.S. Gulf Coast region makes them particularly vulnerable to hurricane or tropical storm risk. In addition, terrorists may target our physical facilities and computer hackers may attack our electronic systems.

If one or more facilities or electronic systems that we own or that deliver products to us or that supply our facilities are damaged by severe weather or any other disaster, accident, catastrophe, terrorist attack or event, our operations could be significantly interrupted. These interruptions could involve significant damage to people, property or the environment, and repairs could take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' product is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make

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significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our securities.

We believe that EPCO maintains adequate insurance coverage on our behalf, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our products. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. For example, following the hurricanes in 2005 and 2008, certain types of insurance coverage for our Gulf of Mexico assets have become more expensive. In the future, circumstances may arise whereby EPCO may not be able to renew existing insurance policies on our behalf or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

The use of derivative financial instruments could result in material financial losses by us.

Historically, we have sought to limit a portion of the adverse effects resulting from changes in energy commodity prices and interest rates by using derivative instruments. Derivative instruments typically include futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though monitored by management, hedging activities can result in losses that might be material to our financial condition, results of operations and cash flows. Such losses could occur under various circumstances, including those situations where a counterparty does not perform its obligations under a hedge arrangement, the hedge is not effective in mitigating the underlying risk, or our risk management policies and procedures are not followed. Adverse economic conditions, such as the financial crisis that developed in the fourth quarter of 2008 and continued into 2009, increase the risk of nonpayment or performance by our hedging counterparties.

See Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for a discussion of our derivative instruments and related hedging activities.

Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

Risks of nonpayment and nonperformance by customers are a major consideration in our businesses, and our credit procedures and policies may not be adequate to sufficiently eliminate customer credit risk. Further, adverse economic conditions, such as the credit crisis that developed in the fourth quarter of 2008 and continued into 2009, increase the risk of nonpayment and nonperformance by customers, particularly customers that are smaller companies. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

Our primary market areas are located in the Gulf Coast, Southwest, Rocky Mountain, Northeast and Midwest regions of the U.S. We have a concentration of trade receivable balances due from major integrated oil companies, independent oil companies and other pipelines and wholesalers. These concentrations of market areas may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors.

Our consolidated revenues are derived from a wide customer base. Our largest non-affiliated customer for 2012 was BP and its affiliates, which accounted for 9.5% of our consolidated revenues for this period. Our largest non-affiliated customer for 2011 and 2010 was Shell Oil Company and its affiliates, which accounted for 10.6% and 9.4% of our consolidated revenues during these years, respectively.

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See Note 2 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for a discussion of our allowance for doubtful accounts.

Our risk management policies cannot eliminate all commodity price risks. In addition, any non-compliance with our risk management policies could result in significant financial losses.

When engaged in marketing activities, it is our policy to maintain physical commodity positions that are substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to earn a margin for the commodity purchased by selling the same commodity for physical delivery to third party users, such as producers, wholesalers, independent refiners, marketing companies or major oil companies. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover these transactions. We are also exposed to basis risks when a commodity is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on product we own, such as pipeline linefill, which must be maintained in order to facilitate transportation of the commodity on our pipelines. In addition, our marketing operations involve the risk of non-compliance with our risk management policies. We cannot assure you that our processes and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved. If we were to incur a material loss related to commodity price risks, including non-compliance with our risk management policies, it could have a material adverse effect on our financial position, results of operations and cash flows.

Our pipeline integrity program as well as compliance with pipeline safety laws and regulations may impose significant costs and liabilities on us.

The DOT requires pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in HCAs. The majority of the costs to comply with this integrity management rule are associated with pipeline integrity testing and any repairs found to be necessary as a result of such testing. 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 will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. 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 DOT has extended its pipeline safety regulations, including integrity management requirements, to certain rural onshore hazardous liquid gathering lines and certain rural onshore low-stress hazardous liquid pipelines. The issuance of these gathering and low-stress pipeline safety regulations, including requirements for integrity management of those pipelines, is likely to increase the operating costs of our pipelines subject to such new requirements.

In January 2012, President Obama signed the 2011 Pipeline Safety Act into law. The 2011 Pipeline Safety Act provides, among other things, stronger oversight of the nation's pipelines, increases the penalties for violations of pipeline safety rules, and complements the DOT's other initiatives. For additional information regarding the pipeline safety regulations and the 2011 Pipeline Safety Act, see "Environmental and Safety Matters—Pipeline Safety Matters" under Part I, Item 1 and 2 of this annual report.

If we were to incur material costs in connection with our pipeline integrity program or pipeline safety laws and regulations, those costs could have a material adverse effect on our financial condition, results of operations and cash flows.

Additional regulations that cause delays or deter new offshore oil and gas drilling could have a material adverse effect on our financial position, results of operations and cash flows.

In April 2010, in an event unrelated to Enterprise's operations, the Deepwater Horizon drilling rig caught fire and sank in the Gulf of Mexico, resulting in an oil spill. As a result, in May 2010, the U.S. Department of the

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Interior ("Interior Department") issued a six-month moratorium that halted drilling of uncompleted and new oil and gas wells.

The drilling suspension was finally lifted by the Interior Secretary on October 12, 2010. However, the timing and process for approving applications for new permits to drill and the cost associated with compliance with various new and enhanced safety and environmental requirements imposed following the Deepwater Horizon incident remains uncertain.

In addition to federal regulatory activity, at least one state has ordered enhanced inspections of oil and gas rigs and required more stringent disaster preparedness plans, and it is possible that other state-level requirements will be imposed on offshore energy production activities.

The effect of new regulatory requirements on offshore energy development in the Gulf of Mexico following the Deepwater Horizon incident, including the prospects and timing of securing permits for offshore energy production activities, are evolving and uncertain. Such uncertainty may cause companies to curtail or delay oil and gas drilling activities, or to redirect resources to other areas such as West Africa, the Caribbean or South America, which may further delay the resumption of drilling activity in the Gulf of Mexico. It is uncertain at this time how and to what extent oil and natural gas supplies from the Gulf of Mexico and other offshore drilling areas will be affected.

Given the scope and effect of the Deepwater Horizon incident to date, as well as statements made by the Interior Secretary, it is expected that additional regulatory compliance and agency review will be required prior to permitting new wells or continued drilling of existing wells, which may affect the cost and timing of oil and gas drilling in the Gulf of Mexico and other offshore areas. A decline in, or failure to achieve anticipated volumes of oil and natural gas supplies due to any of the foregoing factors could have a material adverse effect on our financial position, results of operations and cash flows through reduced gathering and transportation volumes, processing activities, or other midstream services.

Environmental, health and safety costs and liabilities, and changing environmental, health and safety regulation, could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations are subject to various environmental, health and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. Further, we cannot ensure that existing environmental, health and safety regulations will not be revised or that new regulations will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including CERCLA and analogous state laws and regulations, may impose strict, joint and several liability for costs required to clean-up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, third parties, including neighboring landowners, may also have the right to pursue legal actions to enforce compliance or to recover for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

In addition, future environmental, health and safety law developments, such as stricter laws, regulations, permits or enforcement policies, could significantly increase some costs of our operations. Areas of potential future environmental, health and safety law development include the following items.

Greenhouse Gases / Climate Change. Responding to scientific reports regarding threats posed by global climate change, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. In addition, some states, including states in which our facilities or operations are located, have individually or in regional cooperation, imposed restrictions on greenhouse gas emissions under various policies and approaches, including establishing a cap on emissions, requiring efficiency measures, or providing incentives for pollution reduction, use of renewable energy sources, or use of replacement fuels with lower carbon content. The adoption and implementation of any federal, state or local regulations imposing reporting obligations on, or limiting emissions of

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greenhouse gases from, our equipment and operations could require us to incur significant costs to reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the crude oil, natural gas or other hydrocarbon products that we transport, store or otherwise handle in connection with our midstream services. The potential increase in our operating costs could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions, and administer and manage a greenhouse gas emissions program. We may not be able to recover such increased costs through customer prices or rates. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to greenhouse gases, or restrictions on their use, may reduce volumes available to us for processing, transportation, marketing and storage. These developments could have a material adverse effect on our financial position, results of operations and cash flows.

Hydraulic Fracturing. Certain of our customers employ hydraulic fracturing techniques to stimulate natural gas and crude oil production from unconventional geological formations (including shale formations), which entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. The U.S. federal government, and some states and localities, have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to oil and gas drilling activities using hydraulic fracturing techniques, including increased litigation. Additional legislation or regulation could also lead to operational delays and/or increased operating costs in the production of oil and natural gas (including natural gas produced from shale plays like the Eagle Ford, Haynesville, Barnett, Marcellus and Utica Shales) incurred by our customers or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and related servicing activities, it may affect the volume of hydrocarbon projects available to our midstream business and have a material adverse effect on our financial position, results of operations and cash flows.

Please read "Environmental and Safety Matters" under Part I, Item 1 and 2 of this annual report for more information and specific disclosures relating to environmental, health and safety laws and regulations, and costs and liabilities.

Federal, state or local regulatory measures could have a material adverse effect on our financial position, results of operations and cash flows.

The FERC regulates our interstate natural gas pipelines and natural gas storage facilities under the NGA, and our interstate liquids pipelines under the ICA. The STB regulates our interstate propylene pipelines. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

We have ownership interests in natural gas and crude oil pipeline facilities located in the Gulf of Mexico offshore Texas and Louisiana. These facilities are subject to regulation by the FERC and other federal agencies, including the Interior Department, under the OCSLA, and by the DOT's OPS under the NGPSA.

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Colorado, Louisiana, New Mexico, Texas and Wyoming. To the extent our intrastate pipelines engage in interstate transportation, they are also subject to regulation by the FERC pursuant to Section 311 of the NGPA. We also have natural gas underground storage facilities in Louisiana and Texas. Although state regulation is typically less onerous than regulation by the FERC, our provision of services on a nondiscriminatory basis are also subject to challenge by protest and complaint, respectively.

Although our natural gas gathering systems are generally exempt from FERC regulation under the NGA, our natural gas gathering operations could be adversely affected should they become subject to federal regulation of rates and services, or, if the states in which we operate adopt policies imposing more onerous regulation on gas gathering operations. Additional rules and legislation pertaining to these matters are considered and adopted from time to time at both state and federal levels. We cannot predict what effect, if any, such regulatory changes and legislation might have on our operations, but we could be required to incur additional capital expenditures.

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Increasingly stringent federal, state and local laws and regulations governing worker health and safety and the construction and operation of marine vessels may significantly affect our marine transportation operations. Many aspects of the marine transportation industry are subject to extensive governmental regulation by the USCG, the DOT, the Department of Homeland Security, the National Transportation Safety Board ("NTSB") and the U.S. Customs and Border Protection, and to regulation by private industry organizations such as the ABS. The USCG and the NTSB set safety standards and are authorized to investigate vessel accidents and recommend improved safety standards. The USCG is authorized to inspect vessels at will.

For a general overview of federal, state and local regulation applicable to our assets, see "Regulation" included within Part I, Item 1 and 2 of this annual report. This regulatory oversight can affect certain aspects of our business and the market for our products and could have a material adverse effect on our financial position, results of operations and cash flows.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our ability to make distributions to unitholders.

The workplaces associated with our facilities are subject to the requirements of OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could expose us to liability, enforcement, and fines and penalties, and could have a material adverse effect on our financial position, results of operations and cash flows.

The rates of our regulated assets are subject to review and possible adjustment by federal and state regulators, which could adversely affect our revenues.

The FERC, pursuant to the NGA, and rules and regulations promulgated thereunder, regulates the rates for our interstate natural gas pipelines and natural gas storage facilities. These rates must be just and reasonable and not unduly discriminatory. Existing pipeline rates may be challenged by customer complaint or by the FERC, and proposed rate increases may be challenged by protest. If the FERC finds the rates are unjust, unreasonable or otherwise unlawful, the FERC may lower them on a prospective basis. Our rates for these interstate natural gas facilities are derived and charged based on a cost-of-service methodology.

In addition, the FERC, pursuant to the ICA (as amended), the Energy Policy Act and rules and orders promulgated thereunder, regulates the tariff rates for our interstate common carrier liquids pipeline operations. To be lawful under the ICA, interstate tariff rates, terms and conditions of service must be just and reasonable and not unduly discriminatory, and must be on file with the FERC. In addition, pipelines may not confer any undue preference upon any shipper. Shippers may protest (and the FERC may investigate) the lawfulness of new or changed tariff rates. The FERC can suspend those tariff rates for up to seven months. It can also require refunds of amounts collected pursuant to rates that are ultimately found to be unlawful and prescribe new rates prospectively. The FERC and interested parties can also challenge tariff rates that have become final and effective. The FERC can also order new rates to take effect prospectively and order reparations for past rates that exceed the just and reasonable level up to two years prior to the date of a complaint. Due to the complexity of rate making, the lawfulness of any rate is never assured. A successful challenge of our rates could adversely affect our revenues.

The FERC uses prescribed rate methodologies for approving regulated tariff rates for interstate liquids pipelines. The FERC's indexing methodology currently allows a pipeline to increase its rates by a percentage linked to the PPI. As an alternative to using the indexing methodology, interstate liquids pipelines may elect to support rate filings by using a cost-of-service methodology, market-based rates or agreements with all of the pipeline's shippers that the rate is acceptable. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC's approved methodology for approving rates, or challenges to our application of that methodology, could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow.

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The intrastate liquids pipeline transportation services we provide are subject to various state laws and regulations that apply to the rates we charge and the terms and conditions of the services we offer. Although state regulation typically is less onerous than FERC regulation, the rates we charge and the provision of our services may be subject to challenge.

Our partnership status may be a disadvantage to us in calculating our cost of service for rate-making purposes.

In 2005, the FERC issued a policy statement permitting the inclusion of an income tax allowance in the cost of service-based rates of a pipeline organized as a tax pass through partnership entity to reflect actual or potential income tax liability on public utility income, if the pipeline proves that the ultimate owners of its partnership interests have an actual or potential income tax liability on such income.

In 2008, the FERC issued a policy statement in which it declared that it would permit master limited partnerships ("MLPs"), such as us, to be included in rate of return proxy groups for determining rates for services by natural gas and crude oil pipelines. The FERC's rate of return policy remains subject to change.

The FERC's income tax allowance policy and related issues continue to be contested issues and the FERC's policy remains subject to change. Future challenges to the FERC's treatment of income tax allowances in cost of service, particularly with respect to pipelines organized as partnerships, could result in changes to the FERC's current policy and could adversely affect our revenues for any of our rates that are calculated using cost of service rate methodologies.

The adoption and implementation of new statutory and regulatory requirements for derivative transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in 2010 (the "Dodd-Frank Act") provides for new statutory and regulatory requirements for swaps and other financial derivative transactions, including certain oil and gas hedging transactions. Under the Dodd-Frank Act, the Commodities Futures Trading Commission ("CFTC") has adopted regulations requiring registration of swap dealers and major swap participants, electing the end-user exception for uncleared swaps by certain qualified companies, mandatory clearing of swaps, widespread recordkeeping and reporting, business conduct standards and position limits among other requirements. In September 2012, the U.S. District Court for the District of Columbia vacated and remanded the rules for position limits adopted by the CFTC in October 2011 based on a necessity finding. Several of these requirements, including position limits rules, would allow the CFTC to impose controls that could have an adverse impact on our ability to hedge risks associated with our business and could also increase our working capital requirements to conduct these activities.

Based on an assessment of final rules promulgated by the CFTC, we have determined that we are not a swap dealer, major swap participant or a financial entity, and therefore have determined that we would qualify as an end-user. We will seek to retain our status as an end-user by adopting reasonable measures necessary to avoid becoming a swap dealer, major swap participant or financial entity and other measures to preserve our ability to elect the end-user exception should it become necessary.

A CFTC determination that a swap or group, category, type, or class of swaps must be cleared, and if such swap is made available to trade by a Swap Execution Facility ("SEF") or a Designated Contract Merchant ("DCM"), then we must comply with the rule upon the later of 270 days from the mandatory execution rule or 30 days after the swap is made available for trading by an SEF or a DCM unless the transaction qualifies for, and we choose to elect, the end-user exception. The vast majority of our derivative transactions are transacted through a Derivative Clearing Organization ("DCO"), by whom most of the reporting requirements are borne. Derivative transactions that are not clearable and transactions that are clearable but for which we choose to elect the end-user exception may be subject to new requirements for recordkeeping and reporting and potentially additional credit support arrangements including collateral and margin.

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The CFTC has approved two final rules that address how swap data will be reported to regulators and separately to the public. One rule established recordkeeping requirements and a regulatory reporting regime for swap markets. The other rule established a reporting regime for the public dissemination of swap transaction data in real-time. Both rules affect swap dealers, major swap participants and swap counterparties that are neither swap dealers nor major swap participants, including end-users, swap data repositories, swap execution facilities, designated contract markets and derivatives clearing organizations. While we do not believe the internal costs of reporting will be material to us, the rules and regulations are in a state of fluctuation, and we have not been able to assess the full impact of these rules on our counterparties and our own marketing and hedging activities.

The majority of our financial derivative transactions used for hedging purposes are currently cleared over exchanges that already require the posting of margins or letters of credit based on initial and variation margin requirements. It is possible that the effects of new rules will increase the amount of cash required to support our cleared and uncleared derivative transactions. Furthermore, it is possible that letters of credit issued by banks on our behalf will no longer be considered an acceptable form of margin support which would increase overall cash margin requirements.

Posting of additional cash margin or collateral could affect our liquidity and reduce our ability to use cash for capital expenditures or other company purposes. Even if we ourselves are not required to post additional cash margin or collateral for our derivative contracts, the banks and other derivatives dealers who are our contractual counterparties will be required to comply with other new requirements under the Dodd-Frank Act and related rules, and the costs of their compliance will likely be passed on to customers such as ourselves, thus decreasing the benefits to us of hedging transactions and reducing our profitability.

Risks Relating to Our Partnership Structure

We may issue additional securities without the approval of our common unitholders.

At any time, we may issue an unlimited number of limited partner interests of any type (to parties other than our affiliates) without the approval of our unitholders. Our partnership agreement does not give our common unitholders the right to approve the issuance of equity securities, including equity securities ranking senior to our common units. The issuance of additional common units or other equity securities of equal or senior rank will have the following effects: (i) the ownership interest of a unitholder immediately prior to the issuance will decrease; (ii) the amount of cash available for distribution on each common unit may decrease; (iii) the ratio of taxable income to distributions may increase; (iv) the relative voting strength of each previously outstanding common unit may be diminished; and (v) the market price of our common units may decline.

We may not have sufficient operating cash flows to pay cash distributions at the current level following establishment of cash reserves and payments of fees and expenses.

Because cash distributions on our common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance and capital needs. We cannot guarantee that we will continue to pay distributions at the current level each quarter. The actual amount of cash that is available to be distributed each quarter will depend upon numerous factors, some of which are beyond our control and the control of our general partner. These factors include, but are not limited to: (i) the volume of the products that we handle and the prices we receive for our services; (ii) the level of our operating costs; (iii) the level of competition in our business; (iv) prevailing economic conditions, including the price of and demand for oil, natural gas and other products we transport, store and market; (v) the level of capital expenditures we make; (vi) the amount and cost of capital we can raise compared to the amount of our capital expenditures and debt service requirements; (vii) restrictions contained in our debt agreements; (viii) fluctuations in our working capital needs; (ix) weather volatility; (x) cash outlays for acquisitions, if any; and (xi) the amount, if any, of cash reserves required by our general partner in its sole discretion.

Furthermore, the amount of cash that we have available for distribution is not solely a function of profitability, which will be affected by non-cash items such as depreciation, amortization and provisions for asset impairments. Our cash flows are also impacted by borrowings under credit agreements and similar arrangements. As a result, we may be able to make cash distributions during periods when we record losses and may not be able to

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make cash distributions during periods when we record net income. An inability on our part to pay cash distributions to partners could have a material adverse effect on our financial position, results of operations and cash flows.

We do not have the same flexibility as other types of organizations to accumulate cash and equity to protect against illiquidity in the future.

Unlike a corporation, our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after taking into account reserves for commitments and contingencies, including capital and operating costs and debt service requirements. The value of our common units and other limited partner interests may decrease in correlation with any reduction in our cash distributions per unit. Accordingly, if we experience a liquidity problem in the future, we may not be able to issue more equity to recapitalize.

Our general partner and its affiliates have limited fiduciary responsibilities to, and conflicts of interest with respect to, our partnership, which may permit it to favor its own interests to your detriment.

The directors and officers of our general partner and its affiliates have duties to manage our general partner in a manner that is beneficial to its members. At the same time, our general partner has duties to manage our partnership in a manner that is beneficial to us. Therefore, our general partner's duties to us may conflict with the duties of its officers and directors to its members. Such conflicts may include, among others, the following:

§ neither our partnership agreement nor any other agreement requires our general partner or EPCO to pursue a business strategy that favors us;

§ decisions of our general partner regarding the amount and timing of asset purchases and sales, cash expenditures, borrowings, issuances of additional units, and the establishment of additional reserves in any quarter may affect the level of cash available to pay quarterly distributions to our unitholders;

§ under our partnership agreement, our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

§ our general partner is allowed to resolve any conflicts of interest involving us and our general partner and its affiliates, and may take into account the interests of parties other than us, such as EPCO, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

§ any resolution of a conflict of interest by our general partner not made in bad faith and that is fair and reasonable to us is binding on the partners and is not a breach of our partnership agreement;

§ affiliates of our general partner may compete with us in certain circumstances;

§ our general partner has limited its liability and reduced its fiduciary duties and has also restricted the remedies available to our unitholders for actions that might, without the limitations, constitute breaches of fiduciary duty. As a result of purchasing our units, you are deemed to consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;

§ we do not have any employees and we rely solely on employees of EPCO and its affiliates;

§ in some instances, our general partner may cause us to borrow funds in order to permit the payment of distributions;

§ our general partner may cause us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

§ our general partner intends to limit its liability regarding our contractual and other obligations and, in some circumstances, may be entitled to be indemnified by us;

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§ our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates; and

§ our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

We have significant business relationships with entities controlled by EPCO and Dan Duncan LLC. For information regarding these relationships and related party transactions with EPCO and its affiliates, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. Additional information regarding our relationship with EPCO and its affiliates can be found under Part III, Item 13 of this annual report.

Unitholders have limited voting rights and are not entitled to elect our general partner or its directors. In addition, even if unitholders are dissatisfied, they cannot easily remove our general partner.

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 did not elect our general partner or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The owners of our general partner choose the directors of our general partner.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove our general partner or its officers or directors. Our general partner may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Since affiliates of our general partner currently own approximately 37.2% of our outstanding common units and 100% of our Class B Units, the removal of Enterprise GP as our general partner is highly unlikely without the consent of both our general partner and its affiliates. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence of a takeover premium in the trading price.

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

Unitholders' voting rights are further restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership because of the absence of a takeover premium in the trading price.

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

If at any time our general partner and its affiliates own 85% or more of the common units then outstanding, 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 remaining common units held by unaffiliated persons at a price not less than the then current market price. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may therefore not receive any return on their investment. They may also incur a tax liability upon the sale of their common units.

Our common unitholders may not have limited liability if a court finds that limited partner actions constitute control of our business.

Under Delaware law, common unitholders could be held liable for our obligations to the same extent as a general partner if a court determined that the right of limited partners to remove our general partner or to take other

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action under our partnership agreement constituted participation in the "control" of our business. Under Delaware law, our general partner generally has unlimited liability for our obligations, such as our debts and environmental liabilities, except for those of our contractual obligations that are expressly made without recourse to our general partner.

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 states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that (i) we were conducting business in a state, but had not complied with that particular state's partnership statute; or (ii) your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted "control" of our business.

Unitholders may have liability to repay distributions.

Under certain circumstances, our unitholders may have to repay amounts wrongfully distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. A purchaser of common units who becomes a limited partner is liable for the obligations of the transferring limited partner to make contributions to the partnership that are known to such purchaser of common units at the time it became a limited partner and for unknown obligations if the liabilities could be determined from our partnership agreement.

Our general partner's interest in us and the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner, in accordance with our partnership agreement, may transfer its general partner interest without the consent of unitholders. In addition, our general partner may transfer its general partner interest to a third party in a merger or consolidation or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the sole member of our general partner, currently Dan Duncan LLC, to transfer its equity interests in our general partner to a third party. The new equity owner of our general partner would then be in a position to replace the Board of Directors and officers of our general partner with their own choices and to influence the decisions taken by the Board of Directors and officers of our general partner.

Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in our common units depends, to an extent, on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") on this matter.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate (which is currently at a maximum of 35%) and we would also likely pay additional state income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, the cash available for distribution to our unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material

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reduction in the after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Current law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to a material amount of entity level taxation. In addition, because of widespread state budget deficits and other reasons, several states are evaluating ways to enhance state-tax collections. If any additional state were to impose an entity-level tax upon us or our operating subsidiaries, the cash available for distribution to our unitholders would be reduced.

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 federal income tax treatment of publicly traded partnerships, including us, may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect the tax treatment of certain publicly traded partnerships. Any modification to federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the qualifying income exception in order for us to be treated as a partnership for federal income tax purposes (i.e., not taxable as a corporation). In addition, such changes may affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income, or otherwise adversely affect an investment in our common units. We are unable to predict whether any of these changes or any other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units and the amount of cash available for distribution to our unitholders.

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 items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of the units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. 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 unitholders.

A successful IRS contest of the federal income tax positions we take may adversely impact the market for our common units and the cost of any IRS contest will reduce our cash available for distribution to unitholders.

The IRS may adopt positions that differ from the positions we take, even positions taken with advice of counsel. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may adversely impact the taxable income reported to our unitholders and the income taxes they are required to pay. As a result, any such contest with the IRS may materially and adversely impact the market for our common units and the price at which our common units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to our unitholders.

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

Because our unitholders will be treated as partners to whom we will allocate taxable income (which could be different in amount from the cash that we distribute), our unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive

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any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

Tax gains or losses on the disposition of our common units could be different than expected.

If a common unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized in the sale and the unitholder's tax basis in those common units. Prior distributions to a unitholder in excess of the total net taxable income a unitholder is allocated for a common unit, which decreased the unitholder's tax basis in that common unit, will, in effect, become taxable income to the unitholder if the common unit is sold at a price greater than the unitholder's tax basis in that common unit, even if the price the unitholder receives is less than the unitholder's original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to a unitholder. In addition, because the amount realized may include a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of the cash received from the sale.

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

Investments in our common units by tax-exempt entities, such as individual retirement accounts ("IRAs"), other retirement plans and non-U.S. persons, raise issues unique to them. For example, virtually all of our income allocated to unitholders who are organizations exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income.

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

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

Our common unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of an investment in our common units.

In addition to federal income taxes, our common unitholders will likely be subject to other taxes, such as state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property even if the unitholder does 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, they may be subject to penalties for failure to comply with those requirements. We may own property or conduct business in other states or foreign countries in the future. It is the responsibility of each unitholder to file its own federal, state and local tax returns.

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which could result in us filing two tax returns (and our unitholders could receive two

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Schedules K-1 if relief is not available, as described below) for one fiscal year and could result in the deferral of depreciation deductions allowable in computing our taxable income.

The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the tax year in which the technical termination occurs.

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for 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 of common units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common 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 common units may not be reportable by the unitholder and any cash distributions received by the 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 whose common units are loaned to a short seller to cover a short sale of common units; therefore, 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.

Item 1B. Unresolved Staff Comments.

None.

Item 3. Legal Proceedings.

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. Although we are insured against various risks to the extent we believe it is prudent, there is no assurance that the nature and amount of such insurance will be adequate, in every case, to indemnify us against liabilities arising from future legal proceedings. We are not aware of any material pending legal proceedings at March 1, 2013 to which we are a party, other than routine litigation incidental to our business.

On occasion, we are assessed monetary sanctions by governmental authorities related to administrative or judicial proceedings involving environmental matters. The following information summarizes such matters where the amount of monetary sanctions sought is at least $0.1 million. We do not believe that any expenditures related to the following matters will be material to our consolidated financial statements.

§ We contacted the New Mexico Environment Department to self-disclose possible air emission and permit compliance violations at our facilities located in New Mexico. We discovered these matters during an internal compliance audit of these facilities in 2011. We believe that the eventual resolution of these New Mexico matters will result in a monetary sanction of $0.2 million.

§ The Texas Commission on Environmental Quality ("TCEQ") notified us in the fourth quarter of 2012 that several, existing notices of enforcement issued in connection with air emissions by our Houston-area operations would be combined into one order. We believe that the eventual resolution of this consolidated order will result in penalties or other costs of at least $0.1 million.

For more information regarding our litigation matters, see "Litigation Matters" under Note 18 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report, which subsection is incorporated by reference into this Item 3.

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Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Our common units are listed on the NYSE under the ticker symbol "EPD." As of February 1, 2013, there were approximately 3,037 unitholders of record of our common units. The following table presents high and low sales prices for our common units for the periods presented (as reported by the NYSE Composite ticker tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units with respect to such periods.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2011					
1st Quarter	$44.35	$27.85	$0.5975	April 29, 2011	May 6, 2011
2nd Quarter	$43.95	$38.67	$0.6050	July 29, 2011	August 10, 2011
3rd Quarter	$43.95	$36.36	$0.6125	October 31, 2011	November 9, 2011
4th Quarter	$46.70	$38.01	$0.6200	January 31, 2012	February 9, 2012
2012					
1st Quarter	$52.95	$45.78	$0.6275	April 30, 2012	May 9, 2012
2nd Quarter	$52.94	$45.67	$0.6350	July 31, 2012	August 8, 2012
3rd Quarter	$54.98	$50.78	$0.6500	October 31, 2012	November 8, 2012
4th Quarter	$55.38	$48.52	$0.6600	January 31, 2013	February 7, 2013

Actual cash distributions are paid by us within 45 days after the end of each fiscal quarter. We expect that our cash distributions will be funded primarily through cash provided by operating activities. Although the payment of cash distributions is not guaranteed, we believe that our operations will continue to generate cash sufficient to pay distributions in the future at levels comparable to those presented in the preceding table.

For additional information regarding our cash distributions to partners, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Recent Sales of Unregistered Securities

There were no sales of unregistered equity securities during 2012.

Common Units Authorized for Issuance Under Equity Compensation Plan

See "Securities Authorized for Issuance Under Equity Compensation Plans" under Part III, Item 12 of this annual report, which is incorporated by reference into this Item 5.

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Issuer Purchases of Equity Securities

In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 2,000,000 of our common units. A total of 1,381,600 common units were repurchased under this program; however, no repurchases have been made since 2002. As of December 31, 2012, we and our affiliates could repurchase up to 618,400 additional common units under this program.

A total of 1,356,204 restricted common unit and similar unit awards granted to employees of EPCO vested and were converted to common units during 2012. Of this amount, 408,241 were sold back to us by employees to cover their related withholding tax requirements. The total cost of these treasury units was approximately $20.9 million. We cancelled such treasury units immediately upon acquisition. The following table summarizes our repurchase activity during 2012 in connection with these vesting transactions:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2012 (1)	187,343	$ 51.54	--	--
May 2012 (2)	186,048	$ 49.82	--	--
August 2012 (3)	7,942	$ 53.12	--	--
September 2012 (4)	1,087	$ 54.24	--	--
November 2012 (5)	24,236	$ 52.47	--	--
December 2012 (6)	1,585	$ 50.05	--	--

(1) Of the 632,298 restricted common units that vested in February 2012 and converted to common units, 187,343 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 604,054 restricted common units that vested in May 2012 and converted to common units, 186,048 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 28,131 restricted common units that vested in August 2012 and converted to common units, 7,942 units were sold back to us by employees to cover related withholding tax requirements.
(4) Of the 4,100 equity-based awards that vested in September 2012 and converted to common units, 1,087 units were sold back to us by employees to cover related withholding tax requirements.
(5) Of the 82,621 equity-based awards that vested in November 2012 and converted to common units, 24,236 units were sold back to us by employees to cover related withholding tax requirements.
(6) Of the 5,000 equity-based awards that vested in December 2012 and converted to common units, 1,585 units were sold back to us by employees to cover related withholding tax requirements.

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Item 6. Selected Financial Data.

The following table presents selected historical consolidated financial data of our partnership. As a result of the Holdings Merger, our consolidated financial and operating results prior to November 22, 2010 have been presented as if we were Holdings from an accounting perspective. This information has been derived from and should be read in conjunction with the audited financial statements included under Part II, Item 8 of this annual report. Additional information regarding our results of operations and liquidity and capital resources can be found under Part II, Item 7 of this annual report. As presented in the table, amounts are in millions (except per unit data).

	For Year Ended December 31,				
	2012	2011	2010	2009	2008
Results of operations data: (1)					
Revenues	$42,583.1	$44,313.0	$33,739.3	$25,510.9	$35,469.6
Income from continuing operations	$2,428.0	$2,088.3	$1,383.7	$1,140.3	$1,145.1
Net income	$2,428.0	$2,088.3	$1,383.7	$1,140.3	$1,145.1
Net income attributable to limited partners	$2,419.9	$2,046.9	$320.8	$204.1	$164.0
Earnings per unit: (2)					
Basic	$2.81	$2.48	$1.17	$0.99	$0.89
Diluted	$2.71	$2.38	$1.15	$0.99	$0.89
Other financial data:					
Cash distributions per unit (3)	$2.57	$2.44	$2.27	$2.03	$1.79

	As of December 31,				
	2012	2011	2010	2009	2008
Financial position data: (1)					
Consolidated assets	$35,934.4	$34,125.1	$31,360.8	$27,686.3	$25,780.4
Consolidated debt (4)	$16,201.8	$14,529.4	$13,563.5	$12,427.9	$12,714.9
Equity (5)	$13,296.0	$12,219.3	$11,900.8	$10,473.1	$9,759.4
Total limited partner units outstanding (6)	898.8	881.6	843.7	208.8	184.8

(1) In general, our consolidated results of operations and financial position have been impacted by our capital spending program. For information regarding our capital spending program, see "Liquidity and Capital Resources – Capital Spending" under Part II, Item 7 of this annual report.
(2) Earnings per unit amounts for periods prior to the Holdings Merger in November 2010 have been retroactively presented to reflect the 1.5 to one unit-for-unit exchange that occurred under the Holdings Merger. For information regarding our earnings per unit amounts, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(3) Cash distributions per unit presented for 2009 and 2008 reflect those declared and paid by Holdings. Cash distributions per unit presented for 2010 represent the sum of cash distributions declared and paid by Holdings with respect to the first, second and third quarters of 2010 and the cash distribution declared and paid by Enterprise with respect to the fourth quarter of 2010. Cash distributions per unit for 2012 and 2011 represent those declared and paid by Enterprise with respect to those years. For information regarding our cash distributions, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(4) Consolidated debt has increased over time as a result of our capital spending program. For information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(5) Consolidated equity has increased over time primarily due to the issuance of limited partner units by Enterprise in connection with acquisitions and its capital spending program. For information regarding our consolidated equity, see Note 13 of the Notes to Consolidated Financial Statements

included under Part II, Item 8 of this annual report.

(6) Total units outstanding increased in 2010 in part due to the Holdings Merger in November 2010 and reflects, following the Holdings Merger, the number of Enterprise limited partner common units outstanding. Total units outstanding increased in 2011 in part due to the Duncan Merger in September 2011 and reflects, following the Duncan Merger, the number of Enterprise common units outstanding. Total units outstanding at December 31, 2012, 2011 and 2010 includes the Designated Units issued in connection with the Holdings Merger, which are owned by a privately held affiliate of EPCO that agreed to temporarily waive regular quarterly cash distributions over a five-year period on such units. For information regarding the Designated Units, see Note 1 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. Total units outstanding at December 31, 2012, 2011 and 2010 exclude 4.5 million Class B units of Enterprise.

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

For the Years Ended December 31, 2012, 2011 and 2010

The following information should be read in conjunction with our Consolidated Financial Statements and accompanying notes included under Part II, Item 8 of this annual report. Our financial statements have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States.

Key References Used in this Management's Discussion and Analysis

Unless the context requires otherwise, references to "we," "us," "our," "Enterprise" or "Enterprise Products Partners" are intended to mean the business and operations of Enterprise Products Partners L.P. and its consolidated subsidiaries. References to "EPO" mean Enterprise Products Operating LLC, which is a wholly owned subsidiary of Enterprise, and its consolidated subsidiaries, through which Enterprise Products Partners L.P. conducts its business. Enterprise is managed by its general partner, Enterprise Products Holdings LLC ("Enterprise GP"), which is a wholly owned subsidiary of Dan Duncan LLC, a Texas limited liability company.

The membership interests of Dan Duncan LLC are owned of record by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director and Chairman of the Board of Enterprise GP; (ii) Dr. Ralph S. Cunningham, who is also a director of Enterprise GP; and (iii) Richard H. Bachmann, who is also a director of Enterprise GP. Each of the DD LLC Trustees also currently serves as one of the three managers of Dan Duncan LLC.

References to "EPCO" mean Enterprise Products Company, a Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned of record by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who also serves as Chairman of EPCO; (ii) Dr. Cunningham, who also serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who also serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

As generally used in the energy industry and in this annual report, the acronyms below have the following meanings:

/d	= per day	MMBbls	= million barrels
BBtus	= billion British thermal units	MMBPD	= million barrels per day
Bcf	= billion cubic feet	MMBtus	= million British thermal units
BPD	= barrels per day	MMcf	= million cubic feet
MBPD	= thousand barrels per day	TBtus	= trillion British thermal units

Cautionary Statement Regarding Forward-Looking Information

This annual report on Form 10-K for the year ended December 31, 2012 (our "annual report") contains various forward-looking statements and information that are based on our beliefs and those of our general partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "seek," "goal," "estimate," "forecast," "intend," "could," "should," "will," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Part I, Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

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Overview of Business

We are a publicly traded Delaware limited partnership, the common units of which are listed on the New York Stock Exchange ("NYSE") under the ticker symbol "EPD." We were formed in April 1998 to own and operate certain natural gas liquids ("NGLs") related businesses of EPCO and are now a leading North American provider of midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals.

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and the Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals; crude oil gathering and transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation and services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets include approximately 50,000 miles of onshore and offshore pipelines; 200 MMBbls of storage capacity for NGLs, petrochemicals, refined products and crude oil; and 14 Bcf of natural gas storage capacity. In addition, our asset portfolio includes 24 natural gas processing plants, 21 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and export terminals, and octane enhancement and high-purity isobutylene production facilities.

We conduct substantially all of our business through EPO and are owned 100% by our limited partners from an economic perspective. Enterprise GP manages our partnership and owns a non-economic general partner interest in us. Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers.

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity, L.P. ("Energy Transfer Equity"). For additional information regarding the divestiture of our investment in Energy Transfer Equity, see "Liquidity and Capital Resources – Liquidation of Investment in Energy Transfer Equity" within this Item 7.

We completed the Duncan and Holdings Mergers in September 2011 and November 2010, respectively. We believe these recent merger transactions streamlined and simplified our organizational structure to be more transparent to investors, removed potential conflicts of interest due to common control considerations and reduced public company overhead costs. For additional information regarding these business combinations, see "Duncan and Holdings Mergers" under Part I, Item 1 and 2 of this annual report.

For information regarding our directors and executive officers, see Part III, Item 10 of this annual report.

Basis of Financial Statement Presentation

As a result of the November 2010 merger of Enterprise GP Holdings L.P. ("Holdings") with and into one of our wholly owned subsidiaries (the "Holdings Merger"), Enterprise's consolidated financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). Since we historically consolidated Duncan Energy Partners L.P. ("Duncan Energy Partners") for financial reporting purposes, the September 2011 merger of one of our wholly owned subsidiaries with and into Duncan Energy Partners (the "Duncan

Merger") did not change the basis of presentation of our historical financial statements. See Note 1 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding the basis of presentation of our general purpose financial statements.

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Significant Recent Developments

The following information highlights significant commercial and operational developments during 2012 and through the date of this filing (March 1, 2013). For information regarding recent offerings of our equity and debt securities, see "Liquidity and Capital Resources" within this Item 7.

Enterprise Begins Service at ECHO Crude Oil Terminal

In November 2012, the initial phase of our Enterprise Crude Houston (or "ECHO") storage terminal located in southeast Houston, Texas was partially completed and started receiving deliveries of crude oil. Completion of this first phase provides us with approximately 0.5 MMBbls of crude oil storage capacity (two tanks) at the site. A third tank was completed and placed into service in February 2013. An additional 0.9 MMBbls of storage capacity is expected to be in service as early as the second quarter of 2014. When fully developed, we estimate that the ECHO terminal could have up to 6.0 MMBbls of crude oil storage capacity.

Formation of Eagle Ford Crude Oil Pipeline Joint Venture with Plains

In August 2012, we announced the formation of a 50/50 joint venture, Eagle Ford Pipeline LLC, with Plains All American Pipeline, L.P. ("Plains") to provide crude oil pipeline services to producers in South Texas. The arrangement provides for Enterprise and Plains to consolidate certain segments of previously announced pipeline projects servicing the Eagle Ford Shale supply basin. The joint venture pipeline system is supported by long-term commitments from producers totaling up to 210 MBPD of crude oil. This joint venture is expected to provide shippers with increased market flexibility and enable Enterprise and Plains to optimize their respective capital investments in the area.

The joint venture will include a 140-mile crude oil and condensate line extending from Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and continuing on to Corpus Christi, Texas, and a newly constructed 35-mile pipeline segment from Three Rivers to our Lyssy, Texas station in Wilson County. The system, which is currently under construction, is expected to have a capacity of 350 MBPD and will include a marine terminal facility at Corpus Christi and 1.8 MMBbls of operational storage capacity across the system. Segments of the new pipeline system are expected to be placed into service in the first quarter of 2013, with the balance of the system expected to be placed into service in the third quarter of 2013. Plains will serve as operator of the joint venture's pipeline system.

At Lyssy, the joint venture pipeline will interconnect with the Eagle Ford expansion of our South Texas Crude Oil Pipeline System, which commenced operations in June 2012 (see below). Our South Texas Crude Oil Pipeline System is not part of the new joint venture's pipeline system.

Plans to Build World-Scale Propane Dehydrogenation Unit

In June 2012, we announced plans to build one of the world's largest propane dehydrogenation ("PDH") units, with capacity to produce up to 1.65 billion pounds per year, which equates to approximately 750 thousand metric tons per year or 25 MBPD, of polymer grade propylene. The PDH facility is expected to consume up to 35 MBPD of propane as feedstock and be located in southeast Texas along the Gulf Coast. The new facility will be integrated with our existing propylene fractionation facilities, which will provide operational reliability and flexibility for both the PDH facility and the fractionation facilities. The PDH facility will also be integrated with our polymer grade propylene storage facilities, pipeline system and export terminal. The PDH facility, which is supported by long-term, fee-based contracts, is expected to begin commercial operations during the third quarter of 2015. We are in discussions with additional customers that could lead to the development of additional PDH capacity.

Eagle Ford Expansion of Our South Texas Crude Oil Pipeline System Commences Operations

In June 2012, we announced that the Eagle Ford expansion of our South Texas Crude Oil Pipeline System commenced operations. This pipeline expansion, which has a crude oil transportation capacity of 350 MBPD,

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allows us to serve growing production areas in the Eagle Ford Shale supply basin. The new pipeline originates at our Lyssy station in Karnes County, Texas and extends 147 miles to Sealy, Texas and includes 2.4 MMBbls of crude oil storage, including 0.8 MMBbls in Karnes County, Texas, 0.4 MMBbls in Gonzales County, Texas and 1.2 MMBbls at Sealy. Crude oil supplies arriving at Sealy on the new pipeline are being delivered to Houston area refiners through affiliate and third party owned pipelines. In addition, shippers have access to our new ECHO crude oil storage terminal.

Seaway Pipeline Developments

In June 2012, we and Enbridge Inc. announced that the Seaway Pipeline made its first delivery of crude oil to the Texas Gulf Coast. The arrival marked the first southbound delivery of crude oil by pipeline from the Cushing hub, and gives producers access to all of the major refineries in the Greater Houston area and Texas City. Additional pump station additions and modifications, which were completed in January 2013, are expected to increase the pipeline's throughput capacity.

In March 2012, we secured capacity commitments from shippers to proceed with an additional expansion of the Seaway Pipeline. This expansion project entails the construction of a 512-mile, 30-inch diameter pipeline mostly along the existing route of the Seaway Pipeline. It is anticipated that the new pipeline will commence operations during the first quarter of 2014.

The Seaway Pipeline delivers crude oil from Cushing into the Houston and Texas City, Texas market utilizing affiliate and third party pipelines. Seaway Crude Pipeline Company LLC ("Seaway") is constructing a 65-mile pipeline that will link its pipeline system to our ECHO crude oil storage terminal. Completion of this pipeline segment is expected in the fourth quarter of 2013. In addition, Seaway plans to build an 85-mile pipeline from our ECHO terminal to the Port Arthur/Beaumont, Texas refining center that would provide shippers access to the region's heavy oil refining capabilities. Completion of this pipeline segment is expected in mid-2014.

For additional information regarding the Seaway Pipeline, see our discussion of the Onshore Crude Oil Pipelines & Services segment under Part I, Item 1 and 2 of this annual report.

Yoakum Natural Gas Processing Plant Begins Operations in Eagle Ford Shale

In May 2012, we announced that the first phase (or "train") of our new cryogenic natural gas processing plant at Yoakum, Texas commenced operations. The second train commenced operations in late August 2012. In the aggregate, these two processing trains are processing up to a combined 700 MMcf/d of natural gas and extracting over 90 MBPD of NGLs. The third and final train at the Yoakum facility, which is the same size as each of the first two trains, is currently undergoing commissioning operations and is expected to be fully operational in March 2013.

In April 2012, we completed a 65-mile residue natural gas pipeline linking the Yoakum plant to our Wilson natural gas storage facility and numerous third party markets. In addition, we recently completed construction of 168 miles of pipelines that will transport mixed NGLs extracted at the Yoakum plant to our NGL fractionation and storage complex at Mont Belvieu, Texas. We are also constructing a 173-mile NGL pipeline that will extend from our Yoakum facility to LaSalle County, Texas, and provide NGL connectivity to additional natural gas processing plants. This pipeline extension is expected to begin service during the second quarter of 2013.

Plans to Construct Front Range Pipeline

In April 2012, we, along with WGR Asset Holding Company LLC, an affiliate of Anadarko Petroleum Corporation, and DCP Midstream Front Range LLC formed a new joint venture, Front Range, to design and construct a new NGL pipeline that will originate in the Denver-Julesburg Basin (the "DJ Basin") in Weld County, Colorado and extend 435 miles to Skellytown in Carson County, Texas. Each party holds a one-third ownership interest in the joint venture. The Front Range Pipeline, with connections to our Mid-America Pipeline System and the Texas Express Pipeline, will provide producers in the DJ Basin with access to the Gulf Coast, the largest NGL market in the U.S. Initial capacity on the Front Range Pipeline will be 150 MBPD, which can be readily expanded to 230 MBPD. We will construct and operate the pipeline, which is expected to begin service in the fourth quarter of 2013.

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Expansion of NGL Fractionation Capacity at Mont Belvieu

In March 2012, we announced plans to construct two additional NGL fractionators at our Mont Belvieu, Texas complex (NGL fractionators seven and eight) that are expected to provide us with 170 MBPD of incremental NGL fractionation capacity. The two new fractionation units (each with 85 MBPD of expected capacity) are forecast to commence operations during the fourth quarter of 2013 and support the continued growth of NGL production from resource basins such as the Eagle Ford Shale in Texas and various production areas in the Rocky Mountains and the Mid-Continent.

In early November 2012, construction of our sixth NGL fractionator at Mont Belvieu was completed and it commenced operations. This plant is supported by long-term customer commitments and has a capacity of approximately 85 MBPD. Completion of this plant increased the total NGL fractionation capacity at our Mont Belvieu complex to approximately 485 MBPD. Once NGL fractionators seven and eight are constructed and placed in service, our total gross NGL fractionation capacity at Mont Belvieu (then eight units in total) would approximate 655 MBPD. At that time, our system-wide fractionation capacity is expected to exceed 1.0 MMBPD.

Development of Our ATEX Express Ethane Pipeline

In January 2012, we secured sufficient transportation commitments to support development of our 1,230-mile Appalachia-to-Texas pipeline (the "ATEX Express"), which will transport growing ethane production from the Marcellus and Utica Shale producing areas to the U.S. Gulf Coast. We received additional volume commitments during the third quarter of 2012.

Demand for ethane feedstock over more expensive crude oil-based derivatives within the Gulf Coast petrochemical market has reached over 1 MMBPD. Several petrochemical companies have made announcements to modify, expand or build new facilities that would use ethane as a feedstock. As currently designed, the ATEX Express will have the capacity to transport up to 190 MBPD of ethane from Appalachian production areas to our storage and distribution assets in southeast Texas.

The project would utilize a combination of new and existing infrastructure. The northern portion of the ATEX Express involves construction of a pipeline that would originate in Pennsylvania and extend west, then southwest, to Indiana following existing pipeline corridors in order to minimize the environmental footprint of the project. The southern portion of ATEX Express would utilize a portion of our existing TE Products Pipeline, which would be transferred to ATEX Express and reversed to accommodate southbound delivery of ethane to the U.S. Gulf Coast. At the southern terminus of the ATEX Express in Beaumont, we plan to construct a 55-mile pipeline to provide shippers with access to our NGL storage complex at Mont Belvieu, which would provide them with direct and indirect access to every ethylene plant in the U.S. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014.

Plans to Construct a Crude Oil Pipeline in the Gulf of Mexico with Genesis

In January 2012, we executed transportation agreements with six Gulf of Mexico producers that will support construction of a 149-mile crude oil gathering pipeline serving the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The pipeline will be constructed and owned by Southeast Keathley Canyon Pipeline Company, L.L.C. ("SEKCO"), a 50/50 joint venture owned by us and Genesis Energy, L.P. We will serve as construction manager and operator of the new deepwater crude oil pipeline (the "SEKCO Oil Pipeline"), which is expected to have a capacity of 115 MBPD. The SEKCO Oil Pipeline is expected to begin service by mid-2014.

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General Outlook for 2013

Commercial Outlook

We provide midstream energy services to producers and consumers of natural gas, NGLs, crude oil, refined products and petrochemicals. Factors that can affect the demand for our products and services include global and U.S. economic conditions, the market price and demand for energy, the cost to develop natural gas and crude oil reserves in the U.S., state and federal regulation, and the cost and availability of capital to energy companies to invest in exploration and production activities.

As a result of the current relative prices of crude oil and NGLs compared to the price of natural gas, exploration and production companies continue to focus their drilling activities on shale and other non-conventional resource plays that can produce crude oil and/or NGL-rich natural gas. Based on prices quoted on the futures markets in January 2013, natural gas prices for 2013 are currently priced at approximately 21% relative to the price of crude oil on an energy equivalent basis. In 2012, natural gas was priced at 17% of crude oil on an energy equivalent basis. In general, producers continue to decrease their drilling activity in onshore areas where natural gas production is considered "dry" or "lean" (i.e., the amount of NGLs produced in connection with the natural gas is relatively small). This same trend is also occurring in the Gulf of Mexico, with producers investing capital to develop new sources of crude oil production rather than natural gas.

In recent years, natural gas and NGLs have had a significant feedstock price advantage over more costly crude oil derivatives (such as naphtha), and this trend is expected to continue based on prices quoted on the futures markets in January 2013. This trend is supported by several factors including: (i) geopolitical risk in many areas of the world that are major exporters of crude such as the Middle East; (ii) growing demand for crude oil by China, India and other developing economies; (iii) technological breakthroughs in drilling techniques used by exploration and production companies in connection with shale resource plays in the U.S., which have significantly increased U.S. oil, natural gas and NGL resources and lowered associated finding and development costs; and (iv) the general inability to export natural gas from the U.S attributable to significant capital requirements, long construction timeframes, and permitting and regulatory issues. Many domestic energy producers and energy consumers in the petrochemical, industrial manufacturing and power generation sectors are strategically repositioning their companies accordingly.

We believe this trend in domestic energy production has led to a long-term fundamental change in feedstock selection by the U.S. petrochemical industry, which is the largest consumer of NGLs. Lower NGL feedstock costs have provided U.S. ethylene producers with an inherent global cost advantage, as ethylene crackers in Europe and Asia are mostly limited to using higher-priced naphtha feedstocks (which are priced more closely to crude oil). From 2009 through 2012, ethane and propane have consistently been the most profitable feedstocks in the production of ethylene, and are forecasted to remain so in 2013.

The production cost advantage enjoyed by U.S. petrochemical companies has led them to maximize their consumption of NGLs in the production of ethylene. Since 2009, many of these companies have expanded their operations in the U.S. and are continuing to build flexibility into their existing operations in order to increase their consumption of NGLs (as economically warranted). In addition, non-U.S. based ethylene crackers have responded to the NGL feedstock cost advantage by importing propane, including propane produced in the U.S., to displace crude oil derivatives such as naphtha as feedstock.

Because of the size of U.S. shale-related resources, international petrochemical companies have shown interest in the potential to export ethane from the U.S. In addition, with much of the U.S. petrochemical industry switching to cracking larger amounts of ethane for ethylene production (which yields fewer by-products such as propylene and butadiene) a number of projects, including our own PDH facility, have been announced. These plants specifically target making these by-products and also consume NGLs.

Based on industry publications, domestic production of ethylene in 2012 averaged approximately 144 million pounds per day, which is a 1.0% decrease from 2011 levels. This slight decrease was due in part to certain ethylene producers electing to take extended turnarounds to modify facilities to increase their capacity to use ethane as a feedstock. In 2012, the average ethane and propane consumption of U.S. ethylene producers was approximately

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937 MBPD and 425 MBPD, respectively, which represents an increase of 7 MBPD and 55 MBPD, respectively, over 2011 levels. Ethylene producers consumed a record amount of propane in 2012 when the price of propane was lower relative to that of ethane and taking into account the value of co-products produced when propane is used to manufacture ethylene. As a result, ethane demand by ethylene producers in 2012 was somewhat limited by this increased use of propane.

During 2012, the U.S. ethylene industry increased its capacity to use ethane as a feedstock by approximately 10% to 1.1 MMBPD. We believe the U.S. ethylene industry could consume approximately 250 MBPD of additional ethane feedstocks over the next three years through modifications and expansions of and the elimination of bottlenecks at existing facilities. In addition, several petrochemical companies have announced plans to construct additional world-scale ethylene plants in the U.S. in the coming years.

Because of the market prices of crude oil and NGLs, drilling activity in 2013 is expected to remain robust in shale plays containing crude oil, condensate and NGL-rich natural gas production such as the Eagle Ford, Bakken, Niobrara, Mississippian, Wolfcamp, Woodford, Marcellus and Utica Shales. Conversely, drilling activity in shale plays with predominantly dry natural gas production, such as the Haynesville/Bossier and Fayetteville Shales, is down from peak levels. When natural gas prices improve, we believe that drilling activity in these dry gas plays will improve.

As a result of producers allocating more of their capital budgets to developing NGL-rich natural gas shale plays and their success in extracting such resources, ethane production has increased more rapidly than the ethylene industry's current capability to consume the increase in supplies. This oversupplied situation contributed to a decrease in ethane prices in 2012 when compared to 2011. Ethane prices averaged $0.40 per gallon in 2012 compared to $0.77 per gallon in 2011. Moreover, ethane prices in the fourth quarter of 2012 averaged $0.28 per gallon compared to $0.86 per gallon in the fourth quarter of 2011. We believe this ethane oversupply situation may generally persist until ethylene producers increase their capacity to consume additional ethane feedstock volumes through plant modifications and expansions and the completion of recently announced new ethylene plants.

In the near term, this ethane oversupply situation may result in volatile ethane prices and prolonged periods of ethane rejection by producers and natural gas processors in an effort to balance supply and demand. This could lower the value of our equity NGL production and reduce the volumes that would otherwise be handled by our NGL fractionators and pipelines.

Based on forecasts of drilling activity, the number of wells waiting to be connected to our pipeline systems, and natural depletion of the associated resource basins, we believe that aggregate natural gas pipeline volumes transported by our Jonah Gathering System, Piceance Basin Gathering System and San Juan Gathering System for 2013 could decrease between 5% and 12% compared to volumes transported in 2012. These declines may be mitigated in future years since these areas (including prospects to develop additional unconventional production from geologic formations such as the NGL-rich Mancos and Niobrara Shales) have substantial, undeveloped natural gas reserves with some of the lowest finding costs in the U.S. and are supported by existing pipeline infrastructure to transport the natural gas to market. We believe that as U.S. natural gas and ethane supplies and demand becomes more balanced and natural gas and ethane prices become less volatile, these producing basins could experience an increase in drilling activity to support, and potentially increase, current production levels.

In the Eagle Ford Shale, which runs parallel to the Texas Gulf Coast and adjacent to our Texas Intrastate System, we have completed several pipeline projects that enable us to gather, transport and process approximately 1.0 Bcf/d of new natural gas production from the area. In general, energy companies are continuing to have significant success in the Eagle Ford Shale and have accelerated their associated drilling programs. Production from this region includes crude oil, condensate, NGL-rich natural gas and dry natural gas. Since 2010, we have announced expansions of our natural gas pipeline, storage and processing facilities; NGL pipeline and fractionation facilities; and crude oil pipeline and storage facilities to accommodate production growth from this region. These projects represent approximately $4.0 billion of capital expenditures in the aggregate from 2010 through 2013.

We estimate that crude oil volumes handled by our offshore Gulf of Mexico assets will begin to recover in 2013 from the lower volumes experienced since 2010. Producers continue to increase drilling activity in the Gulf of Mexico following federal regulatory uncertainty in the aftermath of the Deepwater Horizon/Macondo incident in

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2010. Our offshore crude pipelines transported approximately 336 MBPD of crude oil in the fourth quarter of 2012, which is the highest volume since the first quarter of 2010 and prior to the Deepwater Horizon/Macondo incident.

We expect that throughput volumes on our offshore Gulf of Mexico natural gas pipelines will continue to decline in 2013 due to producers focusing more of their near term resources to exploiting onshore and offshore crude oil developments and onshore NGL-rich natural gas producing areas. Based on producer forecasts, we estimate average volumes on our largest offshore natural gas asset, the Independence Hub platform, will approximate 100 MMcf/d during 2013 compared to an average of 313 MMcf/d and 455 MMcf/d during 2012 and 2011, respectively. We believe that as U.S. natural gas supply and demand becomes more balanced and natural gas prices become less volatile, the area near the Independence Hub platform could experience an increase in drilling activity to support, and potentially increase, our estimate of future production levels. Producers connected to our Independence Hub platform paid us $54.6 million of demand fees annually for five years beginning in March 2007 until that period expired in March 2012. The Independence Hub platform now earns its revenue based on the volume it handles. Enterprise owns 80% of the Independence Hub platform.

Price differentials between West Texas Intermediate ("WTI") and Brent crude oil were much wider than normal in 2011, as crude oil production from sources north of the Cushing hub in Oklahoma, including the Bakken Shale in North Dakota and the Canadian Oil Sands, increased without adequate incremental pipeline capacity to transport such supplies to markets along the Gulf Coast. The WTI-Brent pricing spread reached as high as $27 per barrel in October 2011, but contracted somewhat after we and Enbridge announced in November 2011 our plans to reverse and expand the Seaway Pipeline in order to move crude oil from the Cushing hub to the Gulf Coast. In addition to reversal of the Seaway Pipeline, the first phase of which was completed in June 2012, a significant amount of rail capacity was added in 2011 and 2012 in order to move crude from the producing areas and the Cushing hub to refining centers on the Gulf Coast and East Coast of the U.S. Because of the growing availability of domestic crudes, the utilization rate of U.S. Gulf Coast refineries has been increasing as have their exports of petroleum products into global markets. As a result, many refineries are modifying and expanding their facilities in order to process more North American crude oil. We expect North American crude oil supplies to continue to displace imported crude oil volumes, especially imports of light, sweet grades of crude oil. We also expect the U.S. refining industry to continue to evolve based on the growing availability of these new competitively priced crude oils.

Our TE Products Pipeline and related Centennial Pipeline transport refined products produced by refineries on the Gulf Coast to markets in the Midwest and Northeast U.S. As a result of increased refinery production in the Midwest and lower overall demand for refined products within these markets, demand to transport refined products to these markets on our pipelines has decreased. We expect this trend to continue; however, management is actively pursuing projects that will convert portions of these pipeline systems to alternate uses such as the southbound transportation of ethane from the Marcellus and Utica Shale producing areas using the ATEX Express pipeline. The ATEX Express pipeline includes the conversion of one of the two parallel pipelines of the TE Products Pipeline. We expect that the ATEX Express will begin commercial operations in the first quarter of 2014.

In conclusion, despite periods of ethane rejection, we believe that end-user demand for NGLs and increases in NGL-rich natural gas production from shale and other non-conventional resource plays will maintain the utilization rates of our NGL fractionators, pipelines, storage and export facilities and certain of our natural gas pipelines and processing plants during 2013. With approximately $7.2 billion of major organic growth projects currently under construction, we are well positioned for future growth through 2015, and our partnership's large geographic asset footprint continues to provide us with additional growth opportunities. These fee-based projects, anchored by long-term customer agreements, will serve producers in the developing Eagle Ford, Marcellus/Utica, Niobrara, Granite Wash and Barnett shale plays, and provide important energy feedstocks to petrochemical facilities, crude oil refineries and other energy intensive industries.

Liquidity Outlook

The corporate debt and equity capital markets were accessible in 2012. Sovereign credit markets, however, continue to be volatile due to large budget deficits being incurred by the U.S., United Kingdom and many European countries. The cost of our term debt and equity capital declined and the availability of term debt and equity capital improved. Likewise, the general availability of credit commitments from most banks also improved from a year

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ago, except for certain investment banks and European banks, which are being impacted by their cost of capital and sovereign debt concerns.

At December 31, 2012, we had $3.17 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under our $3.5 Billion Multi-Year Revolving Credit Facility. In January 2013, affiliates of EPCO expressed their willingness to purchase at least $100 million of our common units from us in 2013 principally through our distribution reinvestment plan ("DRIP"). The first such purchase was for approximately $25 million and was completed through the reinvestment of distributions we paid to EPCO affiliates in February 2013. On February 1, 2013, we retired a total of $550 million of senior notes that matured. The average interest rate for these retired notes was approximately 6.28%. We initially retired these notes by issuing short-term notes under our commercial paper program.

We currently estimate that our capital expenditures for 2013 will approximate $4.4 billion, which includes approximately $4 billion for growth capital projects and $350 million for sustaining capital expenditures. Based on current market conditions, we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs.

As of the filing date of this report, we have approximately $3.1 billion of senior notes maturing in the period beginning April 1, 2013 through the end of 2015. The U.S. government is expected to continue to run substantial annual budget deficits that will require a corresponding issuance of debt by the U.S. Treasury from 2013 through 2015. The interest rate on U.S. Treasury debt has a direct impact on the cost of our debt. At this time, we are uncertain what the impact of the expected large issuances of U.S. Treasury debt and the prevailing economic and capital market conditions during these future periods will have on the cost and availability of capital. At this time, we have not executed any interest rate swaps to hedge a portion of our expected future debt issuances in connection with the refinancing of our debt. We continue to monitor and evaluate the condition of the capital markets and our interest rate risk with respect to refinancing these maturities and funding our capital expenditures.

In February 2013, we issued 9,200,000 of our common units in a public offering (including an over-allotment amount of 1,200,000 common units) resulting in net proceeds of approximately $486.6 million.

In March 2013, we expect to sell the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, to a third party for $87.1 million in cash. As a result, our first quarter of 2013 net income is expected to include an approximate $53 million gain from the disposal of these assets. The Seminole Pipeline remains connected to our Mont Belvieu complex through a newly constructed pipeline segment that we own.

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Results of Operations

Summarized Consolidated Income Statement Data

The following table summarizes the key components of our results of operations for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2012	2011	2010
Revenues	$42,583.1	$44,313.0	$33,739.3
Costs and expenses:			
Operating costs and expenses:			
Cost of sales	36,015.5	38,292.6	28,723.1
Other operating costs and expenses	2,244.9	2,195.4	1,825.9
Depreciation, amortization and accretion	1,061.7	958.7	936.3
Gains attributable to disposal of assets	(17.6)	(156.0)	(44.4)
Non-cash asset impairment charges	63.4	27.8	8.4
Total operating costs and expenses	39,367.9	41,318.5	31,449.3
General and administrative costs	170.3	181.8	204.8
Total costs and expenses	39,538.2	41,500.3	31,654.1
Equity in income of unconsolidated affiliates	64.3	46.4	62.0
Operating income	3,109.2	2,859.1	2,147.2
Interest expense	(771.8)	(744.1)	(741.9)
Other, net	73.4	0.5	4.5
Benefit from (provision for) income taxes	17.2	(27.2)	(26.1)
Net income	2,428.0	2,088.3	1,383.7
Net income attributable to noncontrolling interests	(8.1)	(41.4)	(1,062.9)
Net income attributable to limited partners	$2,419.9	$2,046.9	$320.8

Consolidated Revenues by Business Segment

The following table presents each business segment's contribution to revenues (net of eliminations and adjustments) for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2012	2011	2010
NGL Pipelines & Services:			
Sales of NGLs and related products	$14,218.5	$16,724.6	$13,449.4
Midstream services	949.9	758.7	753.1
Total	15,168.4	17,483.3	14,202.5
Onshore Natural Gas Pipelines & Services:			
Sales of natural gas	2,395.4	2,866.5	2,928.7
Midstream services	957.2	863.7	772.9
Total	3,352.6	3,730.2	3,701.6
Onshore Crude Oil Pipelines & Services:			
Sales of crude oil	17,548.7	15,962.6	10,710.4
Midstream services	113.0	98.5	84.4
Total	17,661.7	16,061.1	10,794.8
Offshore Pipelines & Services:			
Sales of natural gas	0.4	1.1	1.3

Sales of crude oil	3.3	9.4	9.5
Midstream services	187.8	245.5	299.9
Total	191.5	256.0	310.7
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	5,470.9	6,000.6	4,009.1
Midstream services	738.0	781.8	720.6
Total	6,208.9	6,782.4	4,729.7
Total consolidated revenues	$42,583.1	$44,313.0	$33,739.3

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Selected Energy Commodity Price Data

The following table presents index prices for natural gas, crude oil and selected NGL and petrochemical products for the periods presented:

	Natural Gas, $/MMBtu (1)	Ethane, $/gallon (2)	Propane, $/gallon (2)	Normal Butane, $/gallon (2)	Isobutane, $/gallon (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)	Crude Oil, $/barrel (4)
2010 Averages	$ 4.39	$ 0.60	$ 1.16	$ 1.50	$ 1.58	$ 2.84	$ 0.61	$ 0.48	$79.53
2011 by quarter:									
1st Quarter	$ 4.11	$ 0.66	$ 1.37	$ 1.75	$ 1.85	$ 2.27	$ 0.76	$ 0.68	$94.10
2nd Quarter	$ 4.32	$ 0.78	$ 1.49	$ 1.87	$ 2.02	$ 2.48	$ 0.89	$ 0.79	$102.56
3rd Quarter	$ 4.20	$ 0.78	$ 1.54	$ 1.88	$ 2.09	$ 2.37	$ 0.78	$ 0.67	$89.76
4th Quarter	$ 3.54	$ 0.86	$ 1.44	$ 1.89	$ 2.26	$ 2.24	$ 0.59	$ 0.44	$94.06
2011 Averages	$ 4.04	$ 0.77	$ 1.46	$ 1.85	$ 2.06	$ 2.34	$ 0.76	$ 0.64	$95.12
2012 by quarter:									
1st Quarter	$ 2.72	$ 0.56	$ 1.26	$ 1.93	$ 2.04	$ 2.39	$ 0.69	$ 0.60	$102.93
2nd Quarter	$ 2.21	$ 0.40	$ 0.98	$ 1.62	$ 1.75	$ 2.05	$ 0.66	$ 0.51	$93.49
3rd Quarter	$ 2.80	$ 0.34	$ 0.89	$ 1.44	$ 1.62	$ 2.01	$ 0.51	$ 0.37	$92.22
4th Quarter	$ 3.41	$ 0.28	$ 0.88	$ 1.64	$ 1.82	$ 2.15	$ 0.56	$ 0.48	$88.18
2012 Averages	$ 2.79	$ 0.40	$ 1.00	$ 1.65	$ 1.81	$ 2.15	$ 0.60	$ 0.49	$94.20

(1) Natural gas prices are based on Henry-Hub I-FERC commercial index prices.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer-grade propylene prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by CMAI.
(4) Crude oil prices are based on commercial index prices for West Texas Intermediate as measured on the New York Mercantile Exchange ("NYMEX").

Period-to-period fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. Energy commodity prices during 2012 were generally lower when compared to those in 2011. For example:

§ The weighted-average indicative market price for NGLs (based on prices for such products at Mont Belvieu, Texas, which is the primary industry hub for domestic NGL production) was $1.12 per gallon during 2012 versus $1.46 per gallon during 2011 – a 23% year-to-year decrease.

§ The market price of natural gas (as measured at the Henry Hub in Louisiana) averaged $2.79 per MMBtu during 2012 versus $4.04 per MMBtu during 2011 – a 31% year-to-year decrease.

§ The market price of crude oil (as measured on the NYMEX) averaged $94.20 per barrel during 2012 compared to $95.12 per barrel during 2011 – a 1% year-to-year decrease.

A decrease in our consolidated marketing revenues due to lower commodity energy sales prices may not generate a decrease in gross operating margin or cash available for distributions, since corresponding cost of sales amounts would also be lower due to comparable decreases in the purchase prices of the underlying energy commodities. The same correlation would be true in the case of higher energy commodity sales prices and purchase prices.

We attempt to mitigate any commodity price exposure through our hedging activities as well as through converting keepwhole and similar contracts to fee-based arrangements. See Part II, Item 7A of this annual report for information regarding our commodity hedging activities.

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Consolidated Income Statement Highlights

The following information highlights significant changes in our year-to-year income statement amounts and the primary drivers of such changes.

Comparison of 2012 with 2011. Revenues for 2012 decreased $1.73 billion compared to 2011. NGL, natural gas and petrochemical and refined products marketing revenues for 2012 decreased $3.51 billion primarily due to lower energy commodity prices in 2012. This year-to-year decrease was partially offset by a $1.58 million year-to-year increase in crude oil sales revenues primarily due to higher sales volumes.

Operating costs and expenses for 2012 decreased $1.95 billion when compared to 2011 primarily due to lower overall cost of sales. The cost of sales associated with our NGL, natural gas and petrochemical and refined products marketing activities decreased $3.64 billion year-to-year primarily due to lower energy commodity prices. This year-to-year decrease was partially offset by a $1.36 billion increase in the cost of sales associated with increased crude oil sales volumes.

Depreciation, amortization and accretion in operating costs and expenses increased $103.0 million year-to-year primarily due to new assets that were under construction being placed into service.

Gains attributable to the disposal of assets for 2012 decreased $138.4 million when compared to 2011. Results for 2011 included a $129.1 million gain we recorded in connection with the sale of our Petal and Hattiesburg, Mississippi natural gas storage facilities.

Non-cash asset impairment charges for 2012 increased $35.6 million when compared to 2011 primarily due to the abandonment of certain pipeline and natural gas processing assets. For information regarding such charges, see "Nonrecurring Fair Value Measurements" within Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

General and administrative costs for 2012 decreased $11.5 million when compared to 2011. The year ended December 31, 2011 included $12.0 million of transaction expenses related to the Duncan Merger.

Equity income from our unconsolidated affiliates for 2012 increased $17.9 million when compared to 2011 primarily due to improved results from the Seaway Pipeline partially offset by a decrease in equity earnings from Energy Transfer Equity. Equity earnings from our investment in the Seaway Pipeline increased $36.7 million year-to-year due to the completion of its reversal project during the second quarter of 2012. Our equity in the earnings of Energy Transfer Equity was $2.4 million for 2012 compared to $14.8 million for 2011. We liquidated our remaining investment in Energy Transfer Equity common units in early 2012.

Interest expense for 2012 increased $27.7 million when compared to 2011. On a weighted-average basis, the effective interest rates we paid on our consolidated debt during 2012 were essentially unchanged with respect to those paid during 2011. This increase in interest expense was primarily due to generally higher debt levels partially offset by higher capitalized interest. Our average debt principal balance for 2012 was $15.3 billion compared to $14.59 billion for 2011. Interest costs capitalized in connection with our capital spending program increased $10.1 million year-to-year.

Other income for 2012 increased $72.9 million when compared to 2011 primarily due to the $68.8 million in gains we recorded in connection with the liquidation of our investment in Energy Transfer Equity, which was completed in April 2012. For additional information regarding these sales, see "Liquidity and Capital Resources – Liquidation of Investment in Energy Transfer Equity" within this Item 7.

We recognized a net income tax benefit of $17.2 million for 2012 compared to a $27.2 million expense for income taxes in 2011. The $44.4 million year-to-year change in income taxes is primarily due to a $45.3 million benefit related to the conversion of certain of our subsidiaries to limited liability companies during 2012.

Comparison of 2011 with 2010. Revenues for 2011 increased $10.57 billion when compared to 2010. NGL and petrochemical and refined products marketing revenues for 2011 increased $5.27 billion primarily due to

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higher energy commodity prices in 2011. Crude oil marketing revenues for 2011 increased $5.25 billion attributable to higher sales volumes, which accounted for $3.53 billion of the year-to-year increase, and higher sales prices for the remaining increase. These year-to-year increases were partially offset by a $62.4 million year-to-year decrease in natural gas sales revenues primarily due to lower sales volumes.

Operating costs and expenses for 2011 increased $9.57 billion when compared to 2010 primarily due to higher overall cost of sales. The cost of sales associated with our NGL and petrochemical and refined products marketing activities increased $4.80 billion year-to-year primarily due to higher energy commodity prices. The cost of sales associated with our crude oil marketing activities increased $5.01 billion year-to-year primarily due to higher sales volumes, which accounted for $3.4 billion of the year-to-year increase, and higher prices for the remaining increase. These year-to-year increases were partially offset by a $239.3 million decrease in cost of sales associated with lower natural gas prices.

Other operating costs and expenses for 2011 increased $369.5 million when compared to 2010. The primary drivers for this year-to-year increase are: (i) a $177.5 million increase attributable to both the timing of acquisitions during each year (e.g., the State Line and Fairplay acquisitions were acquired in May 2010 and therefore did not have a full year of results in 2010) and the placing into service of newly constructed assets (e.g., our Haynesville Extension pipeline commenced operations in November 2011); (ii) a $102.4 million increase attributable to higher maintenance and pipeline integrity expenses; and (iii) a $30.7 million increase in pipeline transmix expenses due to higher prices.

Depreciation, amortization and accretion in operating costs and expenses increased $22.4 million year-to-year primarily due to new assets that were under construction being placed into service and depreciation and amortization attributable to assets acquired in connection with business combinations.

Gains from asset sales and related transactions included in operating costs and expenses increased $111.6 million year-to-year primarily due to a $129.1 million gain we recorded in connection with the sale of our Petal and Hattiesburg, Mississippi natural gas storage facilities in December 2011.

Non-cash asset impairment charges for 2011 increased $19.4 million when compared to 2010 primarily due to the abandonment of certain pipeline and storage assets. For information regarding such charges, see "Nonrecurring Fair Value Measurements" within Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

General and administrative costs for 2011 decreased $23.0 million when compared to 2010. General and administrative costs include $12.0 million of transaction expenses in 2011 for the Duncan Merger and $24.5 million of transaction expenses in 2010 for the Holdings Merger. The remainder of the year-to-year decrease in general and administrative costs is primarily due to lower overall compensation costs.

Equity income from our unconsolidated affiliates for 2011 decreased $15.6 million when compared to 2010 primarily due to lower volumes on the Seaway Pipeline, Centennial Pipeline and those pipelines operated by our investees in the Gulf of Mexico, all of which was partially offset by increased equity earnings from our investment in Energy Transfer Equity.

Interest expense for 2011 increased $2.2 million when compared to 2010. On a weighted-average basis, the effective interest rates we paid on our consolidated debt during 2011 were essentially unchanged with respect to those charged during 2010. Although our average debt principal balances increased from $13.23 billion in 2010 to $14.59 billion in 2011, a substantial portion of the interest costs associated with the new borrowings were capitalized in connection with our capital spending program. Capitalized interest for 2011 increased $59.5 million when compared to 2010.

Net income attributable to noncontrolling interests was $41.4 million for 2011 compared to $1.06 billion for 2010, which included $1.0 billion attributable to the limited partners of Enterprise other than Holdings. As noted under "Basis of Financial Statement Presentation" within this Item 7, Enterprise's financial and operating results prior to November 22, 2010 have been presented as if Enterprise were Holdings from an accounting perspective (i.e., the financial statements of Holdings became the historical financial statements of Enterprise). For periods prior

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to the Holdings Merger, that portion of Enterprise's net income attributable to its limited partner interests owned by third parties and related parties other than Holdings is presented as a component of net income attributable to noncontrolling interests.

Business Segment Highlights

Total segment gross operating margin was $4.39 billion for 2012 compared to $3.87 billion for 2011. Total segment gross operating margin for 2010 was $3.25 billion.

The following information highlights significant changes in our year-to-year segment results (i.e., gross operating margin amounts) and the primary drivers of such changes. The selected volume statistics presented in the tabular information for each segment are reported on a net basis, taking into account our ownership interests in certain joint ventures, and reflect the periods in which we owned an interest in such operations. These statistics reflect volumes for newly constructed assets from the dates such assets were placed into service and for purchased assets from the date of acquisition.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. For information regarding this financial metric, see "Other Items – Use of Non-GAAP Financial Measures" within this Item 7.

All activities included in our former sixth reportable business segment, Other Investments, ceased on January 18, 2012, which was the date we discontinued using the equity method to account for our previously held investment in Energy Transfer Equity. Our equity earnings from this investment were $2.4 million and $14.8 million for 2012 and 2011, respectively. We recorded a loss in equity earnings of $2.8 million from this investment in 2010.

NGL Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the NGL Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted):

	For Year Ended December 31,		
	2012	2011	2010
Segment gross operating margin:			
Natural gas processing and related NGL marketing activities	$1,443.0	$1,324.4	$989.9
NGL pipelines and related storage	740.7	638.4	604.8
NGL fractionation	284.8	221.4	137.9
Total	$2,468.5	$2,184.2	$1,732.6
Selected volumetric data:			
NGL transportation volumes (MBPD)	2,472	2,284	2,322
NGL fractionation volumes (MBPD)	659	575	485
Equity NGL production (MBPD) (1)	101	116	121
Fee-based natural gas processing (MMcf/d) (2)	4,382	3,820	2,932

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities. In general, equity NGL production decreased in 2012 compared to 2011 and 2010 due to reduced ethane recoveries associated with the weakness in natural gas processing margins resulting from lower NGL prices.
(2) Volumes reported correspond to the revenue streams earned by our gas plants. The increase in fee-based processing volumes in 2012 is primarily due to (i) the start-up of our Yoakum gas plant in May 2012 and (ii) changes in

processing agreements whereby producers are electing to process more of their natural gas on a fee basis in order to retain NGLs extracted from their natural gas streams, which, in turn, also lowers our equity NGL production.

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Natural gas processing and related NGL marketing activities

Comparison of 2012 with 2011. Gross operating margin from our natural gas processing and related NGL marketing activities for 2012 increased $118.6 million when compared to 2011. Gross operating margin from our NGL marketing activities for 2012 increased $150.4 million compared to 2011, of which we attribute a $94.2 million year-to-year increase to higher sales margins and the remainder attributed to higher sales volumes. Our South Texas natural gas processing plants posted a $57.2 million year-to-year increase in gross operating margin primarily due to higher equity NGL and fee-based processing volumes from the start-up of our new Yoakum plant, which commenced operations in May 2012. Gross operating margin from our natural gas processing plants located in the Rocky Mountains included a $20.0 million gain related to a vendor settlement recognized in 2012. In addition, gross operating margin from our Meeker natural gas processing plant increased $34.8 million year-to-year primarily due to the favorable impact of our commodity hedging activities on this facility's processing margins during 2012. Gross operating margin from our Pioneer and Chaco natural gas processing plants decreased $102.1 million year-to-year primarily due to lower equity NGL production volumes. Lastly, gross operating margin from our Louisiana and East Texas natural gas processing plants decreased $32.6 million year-to-year, of which we attribute $25.4 million of the decrease to lower natural gas processing margins.

Comparison of 2011 with 2010. Gross operating margin from our natural gas processing and related NGL marketing activities for 2011 increased $334.5 million when compared to 2010. Gross operating margin from our NGL marketing activities increased $210.6 million year-to-year due to higher NGL sales margins. Gross operating margin from our natural gas processing plants located in the Rocky Mountains increased $71.7 million year-to-year primarily due to higher natural gas processing margins, which accounted for $32.4 million of the year-to-year increase, and higher equity NGL production and fee-based processing volumes in 2011. Collectively, gross operating margin from our natural gas processing plants in southern Louisiana and the San Juan and Permian Basins increased $42.4 million year-to-year primarily due to higher natural gas processing margins in 2011 compared to 2010. Natural gas processing activities on the Fairplay Gathering System, which we acquired in May 2010, accounted for $8.9 million of the year-to-year increase in gross operating margin.

NGL pipelines and related storage

Comparison of 2012 with 2011. Gross operating margin from our NGL pipelines and related storage business for 2012 increased $102.3 million when compared to 2011. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $37.2 million year-to-year primarily due to an increase in system-wide tariffs and other fees. Gross operating margin from our Mont Belvieu NGL storage business increased $22.9 million year-to-year primarily due to higher storage volumes. Gross operating margin from our Houston Ship Channel import/export terminal and a related pipeline increased $19.6 million year-to-year attributable to higher export volumes. Gross operating margin from our South Texas NGL Pipeline System, including the new Eagle Ford NGL Pipeline placed into service in April 2012, increased $45.0 million year-to-year primarily due to higher NGL volumes associated with Eagle Ford Shale production. The foregoing year-to-year increases in gross operating margin from our NGL pipelines and related storage business were partially offset by $20.1 million of net operational measurement gains in 2011 that did not reoccur in 2012.

Comparison of 2011 with 2010. Gross operating margin from our NGL pipelines and related storage business for 2011 increased $33.6 million when compared to 2010. Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased $53.0 million year-to-year primarily due to an increase in revenues attributable to changes in the mix of transportation services provided to customers (e.g., increased long-haul delivery volumes and changes in delivery destinations) during 2011 compared to 2010 and an increase in system-wide tariffs in July 2011. Gross operating margin from our NGL storage activities increased $14.9 million year-to-year primarily due to an increase in storage and terminaling fees charged at our NGL terminals in the northeastern U.S. Gross operating margin from our South Texas NGL Pipeline System increased $5.0 million year-to-year primarily due to a $6.8 million charge we recorded during 2010 related to a dispute involving a pipeline segment on this system.

Collectively, gross operating margin from our NGL pipelines in southern Louisiana decreased $18.5 million year-to-year primarily due to a decrease in transportation volumes. The year-to-year decrease in NGL transportation volumes on our pipelines in southern Louisiana was primarily due to reduced supplies of NGLs in

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2011 compared to 2010 from offshore Gulf of Mexico production developments and reduced volumes of mixed NGLs transported from our Mont Belvieu facility to NGL fractionators in southern Louisiana. Gross operating margin from our Dixie Pipeline and related NGL terminals decreased $13.7 million year-to-year primarily due to lower transportation volumes, which accounted for $10.2 million of the year-to-year decrease, and higher pipeline integrity expenses in 2011. Lastly, gross operating margin from our Houston Ship Channel import/export terminal and a related pipeline decreased $9.2 million year-to-year primarily due to higher operating expenses in 2011.

NGL fractionation

Comparison of 2012 with 2011. Gross operating margin from NGL fractionation for 2012 increased $63.4 million when compared to 2011 primarily due to higher fractionation volumes at our Mont Belvieu complex. We placed into service the fifth and sixth NGL fractionation unit at our Mont Belvieu complex during the fourth quarter of 2011 and 2012, respectively. Completion of these facilities increased total NGL fractionation capacity at our Mont Belvieu complex by about 170 MBPD to a total of approximately 485 MBPD (433 MBPD net to our interest) at the end of 2012.

Comparison of 2011 with 2010. Gross operating margin from NGL fractionation for 2011 increased $83.5 million when compared to 2010. Gross operating margin from our Mont Belvieu NGL fractionators increased $62.9 million year-to-year primarily due to higher NGL fractionation volumes. We placed into service the fourth and fifth NGL fractionation unit at our Mont Belvieu complex during the fourth quarter of 2010 and 2011, respectively. Completion of these facilities increased total NGL fractionation capacity at our Mont Belvieu complex by about 170 MBPD to a total of approximately 400 MBPD (348 MBPD net to our interest) at the end of 2011.

Gross operating margin from our Norco NGL fractionator increased $17.3 million year-to-year primarily due to higher NGL prices, which resulted in higher revenues associated with percent-of-liquids contracts and product blending activities during 2011 compared to 2010. Gross operating margin from our Hobbs NGL fractionator increased $8.4 million year-to-year primarily due to higher NGL fractionation fees. Lastly, gross operating margin decreased $4.9 million year-to-year due to the sale of our Colorado NGL fractionators in March 2011.

Onshore Natural Gas Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Onshore Natural Gas Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted):

	For Year Ended December 31,		
	2012	2011	2010
Segment gross operating margin	$775.5	$675.3	$527.2
Selected volumetric data:			
Natural gas transportation volumes (BBtus/d)	13,634	13,231	11,482

Comparison of 2012 with 2011. Gross operating margin from onshore natural gas pipelines and services for 2012 increased $100.2 million when compared to 2011. Gross operating margin from our Acadian Gas System increased $142.5 million year-to-year primarily due to contributions from our Haynesville Extension pipeline. The Haynesville Extension of our Acadian Gas System commenced operations in November 2011 and transported 1.4 TBtus/d of natural gas during 2012. Gross operating margin from our Texas natural gas pipelines and related storage assets increased $86.4 million year-to-year primarily due to higher firm capacity reservation revenues on the Texas Intrastate System. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services on the Texas Intrastate System during 2012.

The foregoing year-to-year increases in gross operating margin from our natural gas pipelines were partially offset by several factors. Gross operating margin from our San Juan Gathering System decreased $31.2 million year-to-year primarily due to lower gathering and related fees. Gathering fees on our San Juan system are impacted by changes in regional natural gas prices, which decreased on average 31% year-to-year. Gross operating margin from our natural gas marketing activities decreased $24.4 million year-to-year primarily due to lower sales margins. Gross operating margin from our Jonah Gathering System decreased $17.6 million year-to-year primarily due to lower throughput volumes. Likewise, gross operating margin from our Central Treating facility in Colorado

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decreased $9.8 million year-to-year due to lower volumes. Lastly, gross operating margin decreased $38.4 million year-to-year due to the sale of our Mississippi natural gas storage business in December 2011 and the sale of a natural gas gathering system in Alabama in August 2011.

Comparison of 2011 with 2010. Gross operating margin from onshore natural gas pipelines and services for 2011 increased $148.1 million when compared to 2010. Gross operating margin from our Texas Intrastate System increased $63.9 million year-to-year primarily due to higher firm capacity reservation revenues. Increased natural gas production volumes from the Eagle Ford Shale supply basin resulted in stronger demand for our natural gas transportation services during 2011 compared to 2010.

Gross operating margin from our natural gas marketing activities increased $50.7 million year-to-year primarily due to higher sales margins in 2011. Gross operating margin from our Acadian Gas System increased $29.3 million year-to-year primarily due to contributions from our Haynesville Extension pipeline. The Haynesville Extension of our Acadian Gas System commenced operations in November 2011 and transported 1.22 TBtus/d of natural gas during the fourth quarter of 2011. Our State Line and Fairplay natural gas gathering systems, which we acquired in May 2010, contributed $26.5 million of the year-to-year increase in gross operating margin. Gross operating margin from our Piceance Basin Gathering System increased $6.7 million year-to-year primarily due to an increase in transportation volumes.

The foregoing year-to-year increases in gross operating margin from our natural gas pipelines were partially offset by several factors. Gross operating margin from our Jonah Gathering System decreased $14.4 million year-to-year primarily due to a decrease in transportation volumes. Lastly, gross operating margin decreased $14.3 million year-to-year due to the sale of our Mississippi natural gas storage business in December 2011.

Onshore Crude Oil Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Onshore Crude Oil Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted):

	For Year Ended December 31,		
	2012	2011	2010
Segment gross operating margin	$387.7	$234.0	$113.7
Selected volumetric data:			
Crude oil transportation volumes (MBPD)	828	678	670

Comparison of 2012 with 2011. Gross operating margin from our onshore crude oil pipelines and services business for 2012 increased $153.7 million when compared to 2011. Gross operating margin from our crude oil marketing and related activities increased $59.7 million year-to-year primarily due to higher sales margins, which accounted for $35.5 million of the increase, and sales volumes, which accounted for the remaining increase. Our crude oil marketing activities continue to benefit from increased crude oil production volumes from supply basins in the Eagle Ford Shale, Permian Basin and Rocky Mountains regions. Gross operating margin from our South Texas Crude Oil Pipeline System increased $55.7 million year-to-year primarily due to higher transportation volumes attributable to the Eagle Ford Expansion pipeline. Equity earnings from our investment in Seaway increased $36.7 million year-to-year primarily due to the Seaway Pipeline commencing the southbound delivery of crude oil during the second quarter of 2012.

Comparison of 2011 with 2010. Gross operating margin from our onshore crude oil pipelines and services business for 2011 increased $120.3 million when compared to 2010. Gross operating margin from our crude oil marketing and related activities increased $96.2 million year-to-year primarily due to higher sales margins, which accounted for $68.3 million of the increase, and sales volumes, which accounted for the remaining increase. Collectively, gross operating margin from our South Texas Crude Oil System, West Texas System, Red River System and Basin Pipeline increased $34.1 million year-to-year primarily due to higher average fees during 2011, which accounted for $17.6 million of the increase, and a 46 MBPD increase in throughput volumes, which accounted for the remaining increase.

Prior to completion of the Seaway reversal project during the second quarter of 2012, the Seaway pipeline was used to transport crude oil north from the Texas Gulf Coast to the Cushing Hub. Demand for northbound long-

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haul transportation services on the Seaway Pipeline was significantly lower during 2011 due to an oversupply of crude oil at the Cushing hub. As a result, equity earnings from our investment in Seaway decreased $10.8 million year-to-year.

Offshore Pipelines & Services. The following table presents segment gross operating margin and selected volumetric data for the Offshore Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted):

	For Year Ended December 31,		
	2012	2011	2010
Segment gross operating margin	$173.0	$228.2	$297.8
Selected volumetric data: (1)			
Natural gas transportation volumes (BBtus/d)	853	1,065	1,242
Crude oil transportation volumes (MBPD)	300	279	320
Platform natural gas processing (MMcf/d)	291	405	513
Platform crude oil processing (MBPD)	17	17	17

(1) The Offshore Pipelines & Services segment continues to be adversely impacted by lower volumes attributable to the federal offshore drilling moratorium in 2010. In recent months, however, the rig count and drilling activity in the Gulf of Mexico has reached pre-moratorium levels.

Comparison of 2012 with 2011. Gross operating margin from our offshore pipelines and services business for 2012 decreased $55.2 million when compared to 2011. Collectively, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $68.2 million year-to-year primarily due to lower throughput volumes and platform demand fee revenues during 2012 versus 2011. Producers connected to our Independence Hub platform paid us $54.6 million of demand fees annually for five years beginning in March 2007 until that period expired in March 2012. Expiration of these contractual demand fees resulted in a $44.9 million year-to-year decrease in gross operating margin.

Collectively, gross operating margin from our Anaconda Natural Gas Gathering System and Constitution and Poseidon Crude Oil Pipelines increased $22.4 million year-to-year primarily due to natural gas and crude oil production from the Caesar/Tonga development in the Green Canyon area of the Gulf of Mexico that commenced in March 2012. This increase was partially offset by a collective $8.0 million year-to-year decrease in gross operating margin from our Viosca Knoll and HIOS natural gas systems primarily due to lower transportation volumes in 2012.

Comparison of 2011 with 2010. Gross operating margin from our offshore pipelines and services business for 2011 decreased $69.6 million when compared to 2010. Results for 2010 included $27.5 million of gains related to insurance proceeds. Excluding gains from insurance proceeds, gross operating margin from this business decreased $42.1 million year-to-year primarily due to the effects of the federal offshore drilling moratorium (which was in effect from May 2010 to October 2010) and related actions that restricted the issuance of new drilling and well workover permits. These governmental actions reduced production volumes from Gulf of Mexico developments, which decreased the volumes we transport and handle with our offshore assets.

Collectively, gross operating margin from our Independence Hub platform and Independence Trail pipeline decreased $22.0 million year-to-year primarily due to lower throughput volumes attributable to depletion at existing production wells, the watering-out of certain wells and the impact of the federal offshore drilling moratorium which has slowed the drilling of replacement wells.

Equity earnings from our investments in the Cameron Highway Oil Pipeline and Poseidon Oil Pipeline Systems decreased $16.3 million year-to-year primarily due to lower throughput volumes in 2011 compared to 2010. Likewise, gross operating margin from our Shenzi and Constitution Oil Pipelines collectively decreased $4.9 million year-to-year due to lower volumes.

Gross operating margin from our Anaconda Gathering System increased $6.8 million year-to-year primarily due to a system extension that was completed and placed into service during 2011. Excluding Independence Hub, gross operating margin from the remainder of our offshore platform services business decreased

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$6.9 million year-to-year primarily due to higher maintenance expenses at our facilities located in the Garden Banks area of the Gulf of Mexico.

Petrochemical & Refined Products Services. The following table presents segment gross operating margin and selected volumetric data for the Petrochemical & Refined Products Services segment for the years indicated (dollars in millions, volumes as noted):

	For Year Ended December 31,		
	2012	2011	2010
Segment gross operating margin:			
Propylene fractionation and related activities	$193.1	$161.2	$212.4
Butane isomerization	95.8	124.9	84.9
Octane enhancement and related plant operations	100.9	109.1	47.0
Refined products pipelines and related activities	89.9	79.6	170.8
Marine transportation and other	100.2	60.4	69.4
Total	$579.9	$535.2	$584.5
Selected volumetric data:			
Propylene fractionation volumes (MBPD)	72	73	77
Butane isomerization volumes (MBPD)	95	101	89
Octane additive and related plant production volumes (MBPD)	16	17	16
Transportation volumes, primarily refined products and petrochemicals (MBPD)	689	783	893

Propylene fractionation and related activities

Comparison of 2012 with 2011. Gross operating margin from our propylene fractionation and related petrochemical marketing activities for 2012 increased $31.9 million when compared to 2011 primarily due to higher propylene sales margins during the 2012 while production volumes remained fairly constant.

Comparison of 2011 with 2010. Gross operating margin from propylene fractionation and related petrochemical marketing activities for 2011 decreased $51.2 million when compared to 2010. The year-to-year decrease in gross operating margin is primarily due to lower propylene fractionation volumes and sales margins in 2011. Of the total decrease in gross operating margin, we attribute $17.6 million to lower propylene fractionation volumes. Results for 2010 benefited from the combined effects of high demand for propylene and reduced propylene production from third party petrochemical facilities.

Butane isomerization

Comparison of 2012 with 2011. Gross operating margin from butane isomerization for 2012 decreased $29.1 million when compared to 2011. The year-to-year decrease in gross operating margin is primarily due to lower isomerization production volumes (and corresponding by-product production and sales) and processing fees. Isomerization production volumes for 2012 were negatively impacted by extended downtime for maintenance at our octane enhancement facility (which utilizes high purity isobutane feedstock produced at our butane isomerization facility) during 2012. The decrease in by-product production and sales during 2012 accounted for $18.6 million of the $29.1 million year-to-year reduction in gross operating margin.

Comparison of 2011 with 2010. Gross operating margin from butane isomerization for 2011 increased $40.0 million when compared to 2010. The year-to-year increase in gross operating margin is due to a $30.6 million increase in by-product production and sales margins and $9.4 million attributable to higher isomerization production volumes in 2011.

Octane enhancement and related plant operations

Comparison of 2012 with 2011. Gross operating margin from octane enhancement and related high purity isobutylene plant ("HPIB") operations for 2012 decreased a combined $8.2 million when compared to 2011. An estimated $27.1 million year-to-year increase in gross operating margin attributable to higher product sales margins was more than offset by the combined effects of an estimated $19.5 million decrease due to lower sales volumes and

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$15.8 million in higher operating expenses (e.g., catalyst and related costs) during 2012. Our octane enhancement facility experienced extended periods of downtime during 2012, which negatively impacted production and sales volumes and turnaround-related costs.

Comparison of 2011 with 2010. Gross operating margin from octane enhancement and HPIB operations for 2011 increased $62.1 million when compared to 2010. Gross operating margin from our octane enhancement facility for 2011 increased $54.7 million compared to 2010 primarily due to higher motor gasoline additive sales margins, which accounted for $30.6 million of the increase, and volumes, which accounted for $15.9 million of the increase. The remainder of the year-to-year increase in gross operating margin from this facility was attributable to lower operating expenses (primarily repair and maintenance costs) in 2011. The remainder of the year-to-year increase is attributable to the addition of gross operating margin from the HPIB assets we acquired in November 2010.

Refined products pipelines and related activities

Comparison of 2012 with 2011. Gross operating margin from refined products pipelines and related marketing activities for 2012 increased $10.3 million when compared to 2011. Gross operating margin from our TE Products Pipeline and related Centennial pipeline increased $4.9 million year-to-year primarily due to a $44.1 million decrease in operating costs and expenses. Our TE Products Pipeline incurred $31.2 million of costs in 2011 related to the repair of pipeline leaks in New York State, Texas and Louisiana. The remainder of the year-to-year decrease in operating costs and expenses is primarily due to lower expenses in 2012 for operating gains and losses and costs related to transmix (i.e., the comingling of two purity products in a pipeline). Revenues earned by our TE Products Pipeline from the transportation of refined products and NGLs decreased $36.5 million year-to-year primarily due to a 26 MBPD decrease in NGL volumes delivered to Northeast U.S. markets and a 44 MBPD decrease in refined products volumes delivered to Midwest U.S. markets. In general, warmer weather during 2012 compared to 2011 resulted in lower demand for propane used as heating fuel, while shipments of refined products from the Gulf Coast to Midwest markets decreased as a result of lower prices for such products in Midwestern markets than in Gulf Coast markets. Structural shifts in population, reduced demand and increased refinery production in the Midwest have contributed to a decline in demand for the transportation of refined products from the Gulf Coast to the Midwest. Gross operating margin from the marketing of refined products increased $4.8 million year-to-year primarily due to higher sales margins during 2012.

Comparison of 2011 with 2010. Gross operating margin from refined products pipelines and related marketing activities for 2011 decreased $91.2 million when compared to 2010. Gross operating margin from our TE Products Pipeline and related Centennial pipeline decreased $79.4 million year-to-year primarily due to lower throughput volumes attributable to the structural shifts, reduced demand and increased refinery production in the Midwest noted above. In addition, results for the TE Products Pipeline include a $22.8 million year-to-year increase in costs related to the repair of pipeline leaks in New York State, Texas and Louisiana. Gross operating margin from the marketing of refined products decreased $12.3 million year-to-year primarily due to lower sales margins during 2011 associated with forward sales contracts.

Marine transportation and other

Comparison of 2012 with 2011. Gross operating margin from marine transportation and other segment services for 2012 increased $39.8 million when compared to 2011. Results for 2012 include a $24.0 million gain recorded in connection with a legal settlement. The remainder of the year-to-year increase in gross operating margin is primarily due to the combination of $10.4 million in higher marine transportation fees and a $4.7 million decrease in operating expenses associated with our fleet of marine vessels during 2012.

Comparison of 2011 with 2010. Gross operating margin from marine transportation and other segment services for 2011 decreased $9.0 million when compared to 2010. Gross operating margin from marine transportation decreased

$14.4 million year-to-year primarily due to lower revenues resulting from the sale of marine transportation vessels in February 2011 that comprised our former bunker fuel transportation fleet. Gross operating margin from other services increased $5.4 million year-to-year primarily due to our acquisition of truck transport operations from EPCO in September 2010.

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Liquidity and Capital Resources

At December 31, 2012, we had $3.17 billion of consolidated liquidity, which is defined as unrestricted cash on hand plus borrowing capacity available under EPO's $3.5 Billion Multi-Year Revolving Credit Facility. Based on current market conditions (as of the filing date of this annual report), we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs.

We expect to issue additional equity and debt securities to assist us in meeting our future liquidity and capital spending requirements. We have a universal shelf registration statement (the "2010 Shelf") on file with the SEC. The 2010 Shelf allows Enterprise Products Partners L.P. and EPO (on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. The 2010 Shelf will expire in July 2013, at which time we expect to file a replacement universal shelf registration statement.

Consolidated Debt

We had $16.18 billion of principal amounts outstanding under consolidated debt agreements at December 31, 2012. The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at December 31, 2012 for the next five years, and in total thereafter (dollars in millions):

		Scheduled Maturities of Debt					
	Total	2013	2014	2015	2016	2017	After 2017
Commercial Paper Notes	$346.6	$346.6	$--	$--	$--	$--	$--
Senior Notes	14,300.0	1,200.0	1,150.0	1,300.0	750.0	800.0	9,100.0
Junior Subordinated Notes	1,532.7	--	--	--	--	--	1,532.7
Total	$16,179.3	$1,546.6	$1,150.0	$1,300.0	$750.0	$800.0	$10,632.7

We expect to refinance the current maturities of our consolidated debt obligations at or prior to their maturity.

Commercial Paper Notes. In August 2012, EPO established a commercial paper program under which it may issue (and have outstanding at any time) up to $2.0 billion in the aggregate of short-term commercial paper notes. As of December 31, 2012, a total of $346.6 million of notes were outstanding under this program. These notes matured in January 2013. The fixed interest rates for these notes ranged from 0.30% to 0.50%. Proceeds generated from the issuance of our commercial paper notes are used for general company purposes.

We intend to maintain a minimum available borrowing capacity under EPO's existing $3.5 Billion Multi-Year Revolving Credit Facility equal to any amount outstanding under commercial paper notes as a back-stop to the program. All commercial paper notes issued under the program are senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P.

Senior Notes. In February 2012, EPO issued $750.0 million in principal amount of 30-year unsecured Senior Notes EE at 99.542% of their principal amount. Senior Notes EE have a fixed interest rate of 4.85% and mature on August 15, 2042. Net proceeds from the issuance of Senior Notes EE were used to repay amounts due upon the maturity of $490.5 million principal amount of EPO Senior Notes S due February 2012 and $9.5 million principal amount of TEPPCO Senior Notes due February 2012 and for general company purposes.

In August 2012, EPO issued $650.0 million in principal amount of 3-year unsecured Senior Notes FF at 99.941% of their principal amount and $1.1 billion in principal amount of 30-year unsecured Senior Notes GG at 99.470% of their principal amount. Senior Notes FF have a fixed interest rate of 1.25% and mature on August 13, 2015, and Senior Notes GG have a fixed interest rate of 4.45% and mature on February 15, 2043. Net proceeds from the issuance of

Senior Notes FF and GG were used to temporarily reduce borrowings under EPO's $3.5 Billion Multi-Year Revolving Credit Facility and for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed Senior Notes EE, FF and GG on an unsecured and unsubordinated basis. These senior notes rank equal with EPO's existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These

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senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict EPO's ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

EPO utilized the 2010 Shelf to issue its Senior Notes EE in February 2012 and Senior Notes FF and GG in August 2012. For additional information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Issuance of Common Units

The following table summarizes the issuance of Enterprise common units during the years indicated in connection with its underwritten equity offerings, "at-the-market" program, and quarterly DRIP and employee unit purchase plan ("EUPP") (dollars in millions, number of units issued as shown):

	Number of Common Units Issued	Net Proceeds Received	
Year Ended December 31, 2010: (1)			
Common units issued in connection with underwritten offerings	37,950,000	$	1,346.7
Common units issued in connection with the DRIP and EUPP	8,378,053		273.8
Total	46,328,053	$	1,620.5
Year Ended December 31, 2011:			
Common units issued in connection with underwritten offerings	10,350,000	$	448.5
Common units issued in connection with the DRIP and EUPP	2,337,904		94.4
Total	12,687,904	$	542.9
Year Ended December 31, 2012:			
Common units issued in connection with underwritten offerings	9,200,000	$	473.3
Common units issued in connection	3,978,545		203.8

with the at-the-market program (2)			
Common units issued in connection with the DRIP and EUPP	2,814,660		139.7
Total	15,993,205	$	816.8

(1) Of the 46,328,053 common units issued during 2010, 33,103,053 were issued prior to the Holdings Merger. As a result, net cash proceeds from these pre-Holdings Merger common unit issuances are a component of cash contributions from noncontrolling interests as presented on our Statements of Cash Flows. Net cash proceeds from these pre-Holdings Merger issuances were approximately $1.1 billion. See Note 1 of the Notes to Consolidated Financial Statements for information regarding the basis of presentation of our consolidated financial statements for 2010 in connection with the Holdings Merger.
(2) The sale of common units under the at-the-market program was initiated during the third quarter of 2012.

In September 2012, we utilized the 2010 Shelf to issue 9,200,000 common units (including an over-allotment of 1,200,000 common units) to the public at an offering price of $53.07 per unit, which generated total net cash proceeds of $473.3 million.

In May 2012, we entered into an equity distribution agreement with certain broker-dealers pursuant to which we may offer and sell up to $1.0 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this "at-the-market" program, we may sell common units under the agreement from time to time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. A registration statement covering the issuance and sale of common units pursuant to this agreement was filed with the SEC in March 2012. For the year ended December 31, 2012, we issued 3,978,545 common units under this program for an aggregate price of $205.4 million, resulting in total net cash proceeds of $203.8 million. Proceeds from these sales were used for general company purposes, including funding capital expenditures.

In January 2013, affiliates of privately-held EPCO, which own our general partner and approximately 37.2% of our limited partner interests, expressed their willingness to purchase at least $100 million of our common units from us during 2013 principally through our DRIP. The investment amount for each of the first, second, third

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and fourth quarters of 2013 is expected to be at least $25 million per quarter. The first reinvestment of approximately $25 million occurred in connection with our February 2013 distribution payment.

Using the 2010 Shelf, we issued 9,200,000 common units (including an over-allotment of 1,200,000 common units) in February 2013 to the public at an offering price of $54.56 per unit. This equity offering generated net cash proceeds of $486.6 million, which were used for general company purposes.

For additional information regarding our registration statements, see Note 13 of the Notes to Consolidated Financial Statements included under Item 8 of this annual report.

Credit Ratings

As of March 1, 2013, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were: BBB+ from Standard and Poor's; Baa2 from Moody's; and BBB from Fitch Ratings, and the credit ratings of EPO's short-term senior unsecured debt securities were: A-2 from Standard and Poor's, P-2 from Moody's and F-2 from Fitch Ratings. EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies. The ratings from Fitch Ratings were not solicited.

Designated Units Issued in Connection with Holdings Merger

In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular quarterly cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). The temporary distribution waiver remains in effect for five years following the closing date of the Holdings Merger, which was completed in November 2010.

Distributions paid to partners during calendar years 2011 and 2012 excluded 30,610,600 and 26,130,000 Designated Units, respectively. For the remaining term of the waiver agreement, the number of Designated Units outstanding is as follows for distributions paid or to be paid, if any, during the following calendar years: 23,700,000 during 2013; 22,560,000 during 2014; and 17,690,000 during 2015. The number of our distribution-bearing units will increase as the number of Designated Units decreases. For example, the number of our distribution-bearing units increased by 2,430,000 beginning with the February 2013 distribution and will increase in subsequent years as the number of Designated Units declines as scheduled in the waiver agreement.

Conversion of Class B Units to Common Units Expected in 2013

In connection with the merger of TEPPCO Partners, L.P. with one of our wholly owned subsidiaries in October 2009 (the "TEPPCO Merger"), a privately held affiliate of EPCO exchanged a portion of its TEPPCO units (based on a 1.24 exchange ratio) for 4,520,431 of our Class B units in lieu of receiving common units. The Class B units will automatically convert into the same number of common units on the date immediately following the payment date for the sixteenth regular quarterly distribution following the closing date of the TEPPCO Merger. We expect this conversion will occur during the third quarter of 2013. Until the conversion occurs, the Class B units are not entitled to receive regular quarterly cash distributions; however, the Class B units are entitled to vote together with the common units as a single class on partnership matters and, except for the payment of distributions prior to conversion, have the same rights and privileges as our common units.

Liquidation of Investment in Energy Transfer Equity

At December 31, 2011, we owned 29,303,514 common units of Energy Transfer Equity. On January 18, 2012, we sold 22,762,636 of these common units in a private transaction, which generated cash proceeds of $825.1 million. As a result of the January 18 transaction, our ownership interest in Energy Transfer Equity was reduced below 3%, and we discontinued using the equity method to account for this investment and began accounting for it as an investment in available-for-sale equity securities. The remaining 6,540,878 units were sold systematically through April 27, 2012 and generated additional total cash proceeds of $270.2 million. In the aggregate, the

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liquidation of this investment during 2012 resulted in $68.8 million of gains that are presented as a component of other income.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods indicated (dollars in millions). For additional information regarding our cash flow amounts, please refer to the Statements of Consolidated Cash Flows included under Part II, Item 8 of this annual report.

	For Year Ended December 31,		
	2012	2011	2010
Net cash flows provided by operating activities	$2,890.9	$3,330.5	$2,300.0
Cash used in investing activities	3,018.8	2,777.6	3,251.6
Cash provided by (used in) financing activities	124.2	(598.6)	961.1

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. As a result, these cash flows are exposed to certain risks. We operate predominantly in the midstream energy industry. We provide products and services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. The products that we process, sell, transport or store are principally used as fuel for residential, agricultural and commercial heating; as feedstocks in petrochemical manufacturing; and in the production of motor gasoline. Reduced demand for our services or products by industrial customers, whether because of a decline in general economic conditions, reduced demand for the end products made with our products, or increased competition from other service providers or producers due to pricing differences or other reasons, could have a negative impact on our earnings and operating cash flows. For a more complete discussion of these and other risk factors pertinent to our business, see Part I, Item 1A of this annual report.

The following information highlights significant year-to-year fluctuations in our consolidated cash flow amounts:

Comparison of 2012 with 2011

Operating Activities. Cash provided by operating activities decreased $439.6 million year-to-year. A $442.5 million year-to-year increase in cash attributable to overall higher partnership income (after adjusting our $339.7 million year-to-year increase in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows) was more than offset by a $363.6 million year-to-year increase in cash used for inventories and a $407.3 million year-to-year decrease in cash flow generally attributable to the timing of cash receipts and disbursements related to operations. In addition, distributions from unconsolidated affiliates decreased $39.7 million year-to-year primarily due to an $80.6 million decrease in cash distributions from Energy Transfer Equity partially offset by a $39.7 million increase in distributions from Seaway. For information regarding significant year-to-year changes in our consolidated net income and underlying segment results, see "Results of Operations" within this Item 7. We liquidated our remaining investment in Energy Transfer Equity in April 2012.

Investing Activities. The $241.2 million year-to-year increase in cash used for investing activities was primarily due to increased investments in unconsolidated affiliates, partially offset by reduced capital expenditures and higher proceeds from asset sales. Investments in unconsolidated affiliates increased $579.5 million year-to-year primarily due to capital expenditures incurred in connection with modifications to and expansion of the Seaway Pipeline, construction of the Texas Express Pipeline, and those involving the Eagle Ford Crude Oil Pipeline. Capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs, decreased $244.1 million year-to-year. Proceeds from the disposal of assets increased $145.0 million year-to-year primarily due to the liquidation of our remaining investment in Energy Transfer Equity in 2012.

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Financing Activities. Cash provided by financing activities was $124.2 million during 2012 compared to cash used in financing activities of $598.6 million during 2011. The $722.8 million change in cash flows from financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements increased $738.4 million year-to-year. EPO issued $2.5 billion and repaid $1.0 billion in principal amount of senior notes during 2012, compared to the issuance of $2.75 billion and repayment of $450.0 million in principal amount of senior notes during 2011. In addition, net repayments under our consolidated revolving bank credit facilities and term loans decreased $1.14 billion year-to-year. For additional information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

§ Cash outflows related to the monetization of interest rate derivative instruments increased $124.6 million year-to-year. During 2012, we settled a number of forward starting swaps and fixed-to-floating interest rate swaps resulting in a combined net cash outflow of $147.8 million in connection with the issuance of senior notes. Likewise in 2011, we settled a number of forward starting swaps and treasury locks resulting in a net cash outflow of $23.2 million in connection with the issuance of senior notes. For information regarding our interest rate hedging activities, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

§ Cash distributions paid to limited partners increased $204.3 million year-to-year primarily due to a higher number of distribution-bearing common units outstanding and the associated quarterly distribution rates.

§ Net cash proceeds from the issuance of common units increased $273.9 million year-to-year. In total, we issued an aggregate 15,993,205 common units during 2012 in connection with underwritten offerings and our DRIP, EUPP and at-the-market program. This compares to 12,687,904 common units we issued during 2011 in connection with underwritten offerings and our DRIP and EUPP. For additional information regarding our consolidated partners equity amounts, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Comparison of 2011 with 2010

Operating Activities. Cash provided by operating activities increased by $1.03 billion year-to-year primarily due a $609.4 million year-to-year increase in cash attributable to overall higher partnership income (after adjusting our $704.6 million year-to-year increase in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows) and a $573.3 million year-to-year decrease in cash used for inventories. Cash flow generally attributable to the timing of cash receipts and disbursements decreased $116.0 million year-to-year.

Investing Activities. The $474.0 million year-to-year decrease in cash used for investing activities was primarily due to the following:

§ Cash used for business combinations decreased $1.31 billion year-to-year, primarily due to the acquisition of the State Line and Fairplay natural gas gathering systems for approximately $1.2 billion in May 2010.

§ Proceeds from the disposal of assets increased $947.9 million year-to-year primarily due to the sale of a portion of our investment in Energy Transfer Equity for $375.2 million and the sale of certain natural gas storage facilities for $547.8 million during 2011.

§ Capital spending for property, plant and equipment, net of contributions in aid of construction costs, increased $1.84 billion year-to-year primarily due to our Eagle Ford Shale and Haynesville Shale growth capital projects.

Financing Activities. As noted under "Basis of Financial Statement Presentation" within this Item 7, the financial statements of Enterprise prior to the Holdings Merger were those of Holdings. As presented on our Statements of Consolidated Cash Flows, cash distributions paid to partners during 2010 represent payments to the

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former unitholders of Holdings whereas cash distributions paid to partners during 2011 represent payments to the unitholders of Enterprise. Also, cash distributions paid to noncontrolling interests by Holdings during 2010 primarily represent cash distributions paid to the unitholders of Enterprise (other than Holdings). Cash contributions from noncontrolling interests during 2010 primarily represent proceeds from Enterprise's equity offerings (other than purchases by Holdings).

Cash used in financing activities was $598.6 million during 2011 compared to cash provided by financing activities of $961.1 million during 2010. The $1.56 billion decrease in cash flows from financing activities was primarily due to the following:

§ Net borrowings under our consolidated debt agreements decreased $191.7 million year-to-year. EPO issued $2.75 billion of new senior notes and repaid $450.0 million in senior notes during 2011 compared to the issuance of $2.0 billion in senior notes and repayment of $500.0 million in senior notes and $54.0 million of other long-term debt during 2010. In addition, net repayments under consolidated revolving credit facilities and term loans increased approximately $988.3 million year-to-year.

§ Cash distributions to partners and noncontrolling interests were a combined $2.04 billion during 2011 compared to $1.78 billion during 2010. The increase in cash distributions is primarily due to increases in the number of Enterprise's distribution-bearing common units outstanding (including common units issued in connection with the Holdings Merger and Duncan Merger) and in its quarterly distribution rates.

§ On a combined basis, cash contributions from noncontrolling interests and net cash proceeds from the issuance of common units decreased $1.07 billion year-to-year. Substantially all of the cash contributions from noncontrolling interests during 2010 relate to net cash proceeds generated from the issuance of common units by Enterprise prior to the completion of the Holdings Merger. In total, Enterprise issued 12,687,904 common units and 46,328,053 common units during 2011 and 2010, respectively, in connection with underwritten offerings and its DRIP and EUPP.

Capital Spending

An important part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are positioned to continue to expand our system of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Rocky Mountains, Midcontinent, Northeast and U.S. Gulf Coast regions, including the Niobrara, Barnett, Eagle Ford, Haynesville, Marcellus and Utica Shale plays and deepwater Gulf of Mexico producing regions.

Although our current focus is on expansion through growth capital projects, management continues to analyze potential business combinations, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions. In past years, major oil and gas companies have sold non-strategic assets in the midstream energy sector in which we operate. We believe this trend will continue and we expect independent oil and natural gas companies to consider similar divestitures.

See "Significant Recent Developments" within this Item 7 for information regarding our current and proposed major capital projects, including construction of our ATEX Express long-haul ethane pipeline, world-scale PDH facility, SEKCO Oil Pipeline, the expansion of the Seaway Pipeline and multiple projects in the Eagle Ford Shale.

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The following table summarizes our capital spending for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2012	2011	2010
Capital spending for property, plant and equipment, net: (1)			
Growth capital projects (2)	$3,232.7	$3,552.3	$1,766.2
Sustaining capital projects (3)	365.8	290.3	235.9
Capital spending for business combinations	--	--	1,313.9
Investments in unconsolidated affiliates	609.5	30.0	8.0
Other investing activities	43.1	22.4	--
Total capital spending	$4,251.1	$3,895.0	$3,324.0

(1) On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction and production well tie-ins. Contributions in aid of construction costs were $23.4 million, $24.9 million and $38.7 million for the years ended December 31, 2012, 2011 and 2010, respectively. Growth and sustaining capital amounts presented in the table are presented net of related contributions in aid of construction costs.
(2) Growth capital projects either result in additional revenue streams from existing assets or expand our asset base through construction of new facilities that will generate additional revenue streams.
(3) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to and major renewals of existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues.

For the year ended December 31, 2012, we spent $3.8 billion on growth capital projects, of which $1.5 billion was for Eagle Ford Shale projects and $644 million was for Mont Belvieu projects.

Based on information currently available, we estimate our consolidated capital spending for 2013 will approximate $4.4 billion, which includes estimated expenditures of $4.0 billion for growth capital projects and $350 million for sustaining capital expenditures. Of our total expected growth capital spending for 2013, approximately 60% relates to projects involving our interstate NGL and crude oil pipelines, including construction of our ATEX Express ethane pipeline, expansion of the Rocky Mountain segment of our Mid-America Pipeline System, our share of the costs to construct the Texas Express and Front Range NGL pipelines, and our share of the costs to modify and expand the Seaway Pipeline. In addition, 10% of our total expected growth capital spending for 2013 relates to Eagle Ford Shale projects (e.g., completion of our Yoakum natural gas processing plant and expansions of our NGL and crude oil pipeline assets that serve this important supply basin) and another 10% involves the expansion of our NGL fractionation complex at Mont Belvieu. The remainder of our growth capital spending for 2013 involves a variety of projects that we expect will either result in additional revenue streams from existing assets or expand our asset base through the construction of new assets that will generate additional revenue streams.

Our forecast of consolidated capital expenditures for 2013 is based on our announced strategic operating and growth plans, which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, issuance of additional debt and equity securities, and potential divestitures. We may revise our forecast of capital spending due to factors beyond our control, such as weather related issues, changes in supplier prices or adverse economic conditions. Furthermore, our forecast of capital spending may change as a result of decisions made by management at a later date, which may include the addition of costs associated with unforeseen acquisition opportunities.

Our success in raising capital, including the formation of joint ventures to share costs and risks, continues to be a principal factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we currently intend to make the forecast capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital markets.

At December 31, 2012, we had approximately $1.75 billion in purchase commitments outstanding that relate to our capital spending for property, plant and equipment. These commitments primarily relate to construction projects in Texas, including those in the Eagle Ford Shale and at our Mont Belvieu facility.

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Pipeline Integrity Costs

Our pipelines are subject to safety programs administered by the U.S. Department of Transportation ("DOT"). This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (e.g., NGL, crude oil, refined products and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs. The following table summarizes our pipeline integrity costs, including those attributable to DOT regulations, for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2012	2011	2010
Expensed	$67.2	$64.7	$39.4
Capitalized	79.4	52.6	40.4
Total	$146.6	$117.3	$79.8

We expect the cost of our pipeline integrity program, irrespective of whether such costs are capitalized or expensed, to approximate $118.0 million in 2013.

Critical Accounting Policies and Estimates

In our financial reporting processes, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses for each reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following describes the estimation risk currently underlying our most significant financial statement items:

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include (i) changes in laws and regulations that limit the estimated economic life of an asset, (ii) changes in technology that render an asset obsolete, (iii) changes in expected salvage values, or (iv) significant changes in the forecast life of proved reserves of applicable resource basins, if any.

At December 31, 2012 and 2011, the net carrying value of our property, plant and equipment was $24.85 billion and $22.19 billion, respectively. We recorded $900.5 million, $776.6 million and $745.7 million in depreciation expense for the years ended December 31, 2012, 2011 and 2010, respectively. For additional information regarding our property, plant and equipment, see Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

Long-lived assets, which include property, plant and equipment and intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil or refined products. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Estimates of undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated salvage values. If the carrying value of a long-lived asset is not recoverable, an

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impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is derived from an analysis of the asset's estimated future cash flows, the market value of similar assets and replacement cost of the asset less any applicable depreciation or amortization. In addition, fair value estimates also include usage of probabilities for a range of possible outcomes.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible permanent loss in value of the investment (i.e., other than a temporary decline). Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. Estimates of discounted cash flows are based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment's underlying assets.

A significant change in the assumptions we use to measure recoverability of long-lived assets and equity method investments could result in our recording a non-cash impairment charge. Any such write-down of the value of such assets would increase operating costs and expenses at that time.

During 2012, 2011 and 2010, we recognized non-cash asset impairment charges of $63.4 million, $27.8 million and $8.4 million, respectively, which are a component of operating costs and expenses. For additional information regarding these impairment charges, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. We did not record any non-cash impairment charges related to our equity method investments in 2012, 2011 or 2010.

Amortization Methods and Estimated Useful Lives of Qualifying Intangible Assets

The specific, identifiable intangible assets of a business depend largely upon the nature of its operations. Potential identifiable intangible assets include items such as intellectual property, customer contracts and relationships, and non-compete agreements. The method used to value each intangible asset will vary depending upon a number of factors, including the nature of the asset and the economic returns it is generating or is expected to generate.

Customer relationship intangible assets represent the estimated economic value we assigned to information about customers and the ability to have regular contact with them as a result of business combinations and assets purchases. These relationships may arise from formal contractual arrangements or through routine contact by sales or service representatives. The value we assign to customer relationships is amortized to earnings using methods that closely resemble the pattern in which the economic benefits of the associated oil and natural gas resource basins from which the customers produce are estimated to be depleted. Our estimate of the useful life of each resource basin is predicated on a number of factors, including reserve estimates and the economic viability of production and exploration activities.

Our contract-based intangible assets represent rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement and the Jonah natural gas transportation contracts. A contract-based intangible asset with a finite life is amortized over its estimated useful life (or term), which is the period over which the asset is expected to contribute directly or indirectly to our cash flows. Our estimates of useful life are based on a number of factors, including (i) the expected useful life of the related tangible assets (e.g., a fractionation facility, pipeline or other asset), (ii) any legal or regulatory developments that would impact such contractual rights, and (iii) any contractual provisions that enable us to renew or extend such agreements.

If our assumptions regarding the estimated useful life of an intangible asset were to change, then the amortization period for such asset would be adjusted accordingly. Changes in the estimated useful life of an intangible asset would impact operating costs and expenses prospectively from the date of change. If we determine that an intangible asset's unamortized cost is not recoverable due to impairment, we would be required to reduce the asset's carrying value to its estimated fair value. Any such write-down of the value of an intangible asset would increase operating costs and expenses at that time.

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At December 31, 2012 and 2011, the carrying value of our intangible asset portfolio was $1.57 billion and $1.66 billion, respectively. We recorded $125.7 million, $147.0 million and $137.6 million in amortization expense associated with our intangible assets for the years ended December 31, 2012, 2011 and 2010, respectively. For additional information regarding our intangible assets, see Note 11 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Methods We Employ to Measure the Fair Value of Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. Goodwill impairment testing involves determining the fair value of the associated reporting unit. These fair value amounts are based on assumptions regarding the future economic prospects of the businesses that make up the reporting unit. Such assumptions include (i) discrete financial forecasts for the businesses contained within the reporting unit, which rely on management's estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates.

If the fair value of a reporting unit (including its inherent goodwill) is less than its carrying value, a charge to operating costs and expenses is required to reduce the carrying value of the goodwill to its implied fair value. Based on our most recent goodwill impairment test, the estimated fair value of each of our reporting units was substantially in excess of its carrying value (i.e., by at least 10%).

At December 31, 2012 and 2011, the carrying value of our goodwill was $2.09 billion. We did not record any goodwill impairment charges in 2012, 2011 or 2010. For additional information regarding our goodwill, see Note 11 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists; (ii) delivery has occurred or services have been rendered; (iii) the buyer's price is fixed or determinable; and (iv) collectibility is reasonably assured. We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). For additional information regarding our revenue recognition policies, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. We record any necessary allowance for doubtful accounts as required by our established policy.

Our use of estimates for certain revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the time required to compile actual billing information and receive third party data needed to record transactions for financial reporting purposes. One example of our use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for a specific period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month.

Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying disclosures. If the assumptions underlying our revenue and expense estimates prove to be substantially incorrect, it could result in material adjustments in results of operations between periods. We review our estimates based on currently available information.

Recent Accounting Developments

In December 2011, the Financial Accounting Standards Board ("FASB") issued an accounting standard update enhancing the disclosure of financial instruments and derivative instruments that have been offset on the

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balance sheet or are subject to a master netting arrangement or similar agreement, regardless of whether they offset on the balance sheet. The objective of this enhanced disclosure is to facilitate the comparison of balance sheets between entities that prepare their financial statements using GAAP versus those entities that use International Financial Reporting Standards. We adopted this guidance on January 1, 2013 and will apply its requirements beginning with quarterly report on Form 10-Q for March 31, 2013. The adoption of this new guidance will not have a material impact on our consolidated financial statements.

In February 2013, the FASB issued an accounting standard update enhancing the disclosures of comprehensive income to improve the transparency of reclassifications out of accumulated other comprehensive income to earnings. We adopted this guidance upon issuance and will apply its requirements beginning with our quarterly report on Form 10-Q for the three months ending March 31, 2013. The adoption of this new guidance will not have a material impact on our consolidated financial statements.

Other Items

Use of Non-GAAP Financial Measures

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered an alternative to GAAP operating income. Our non-GAAP gross operating margin by business segment and in total is as follows for the periods presented (dollars in millions):

	For Year Ended December 31,		
	2012	2011	2010
NGL Pipelines & Services	$2,468.5	$2,184.2	$1,732.6
Onshore Natural Gas Pipelines & Services	775.5	675.3	527.2
Onshore Crude Oil Pipelines & Services	387.7	234.0	113.7
Offshore Pipeline & Services	173.0	228.2	297.8
Petrochemical & Refined Products Services	579.9	535.2	584.5
Other Investments (1)	2.4	14.8	(2.8)
Total segment gross operating margin	$4,387.0	$3,871.7	$3,253.0

(1) Represents the equity earnings we recorded from our previously held investment in Energy Transfer Equity. Our reporting for this segment ceased on January 18, 2012 when we stopped using the equity method to account for this investment. See Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding the liquidation of our investment in Energy Transfer Equity.

The following table presents a reconciliation of total segment gross operating margin to GAAP operating income and further to income before income taxes for the periods indicated (dollars in millions):

	For Year Ended December 31,		
	2012	2011	2010
Total segment gross operating margin	$4,387.0	$3,871.7	$3,253.0

Adjustments to reconcile total segment gross operating margin to operating income:			
Amounts included in operating costs and expenses:			
Depreciation, amortization and accretion	(1,061.7)	(958.7)	(936.3)
Non-cash asset impairment charges	(63.4)	(27.8)	(8.4)
Operating lease expenses paid by EPCO	--	(0.3)	(0.7)
Gains attributable to disposal of assets	17.6	156.0	44.4
General and administrative costs	(170.3)	(181.8)	(204.8)
Operating income	3,109.2	2,859.1	2,147.2
Other expense, net	(698.4)	(743.6)	(737.4)
Income before income taxes	$2,410.8	$2,115.5	$1,409.8

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For additional information regarding gross operating margin, see Note 14 of the Notes to Consolidated Financial Statements under Part II, Item 8 of this annual report.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2012 (dollars in millions):

		Payment or Settlement due by Period			
Contractual Obligations	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
Scheduled maturities of debt obligations (1)	$16,179.3	$1,546.6	$2,450.0	$1,550.0	$10,632.7
Estimated cash payments for interest (2)	$17,072.7	$840.4	$1,471.4	$1,350.4	$13,410.5
Operating lease obligations (3)	$363.0	$51.3	$86.9	$70.8	$154.0
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$4,027.2	$911.8	$1,400.6	$952.9	$761.9
NGLs	$1,704.8	$1,136.3	$568.5	$--	$--
Crude oil	$386.1	$386.1	$--	$--	$--
Petrochemicals and refined products	$2,121.8	$1,519.7	$485.1	$117.0	$--
Other	$127.7	$83.9	$14.8	$13.2	$15.8
Underlying major volume commitments:					
Natural gas (in TBtus)	1,442	321	497	348	276
NGLs (in MMBbls)	44	27	17	--	--
Crude oil (in MMBbls)	5	5	--	--	--
Petrochemicals and refined products (in MMBbls)	29	20	7	2	--
Service payment commitments (5)	$745.5	$114.5	$195.9	$178.0	$257.1
Capital expenditure commitments (6)	$1,754.0	$1,754.0	$--	$--	$--
Other long-term liabilities (7)	$205.0	$--	$39.3	$13.2	$152.5
Total	$44,687.1	$8,344.6	$6,712.5	$4,245.5	$25,384.5

(1) Represents contractually scheduled future maturities of our consolidated debt principal obligations. For information regarding our consolidated debt obligations, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

(2) Estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2012, the scheduled maturities of such balances, and the applicable fixed or variable interest rates paid during 2012. With respect to our variable-rate debt obligations, we applied the weighted-average interest rate paid during 2012 to determine the estimated cash payments. See Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for the weighted-average variable interest rate charged in 2012 under our revolving credit facility. In addition, our estimate of cash payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2012. See Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding these derivative instruments. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our junior subordinated notes (due August 2066 through January 2068). Our estimated cash payments for interest with respect to each junior subordinated note are based on the current fixed interest rate for each note applied to the entire remaining term through the respective maturity date.

(3) Primarily represents leases of underground salt dome caverns for the storage of natural gas and NGLs, office space with affiliates of EPCO and land held pursuant to right-of-way agreements.
(4) Represents enforceable and legally binding agreements to purchase goods or services as of December 31, 2012. The estimated payment obligations are based on contractual prices in effect at December 31, 2012 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.
(5) Primarily represents our unconditional payment obligations under firm pipeline transportation contracts.
(6) Represents unconditional payment obligations for services to be rendered or products to be delivered in connection with our capital spending program, including our share of the capital spending of our unconsolidated affiliates.
(7) As reflected on our consolidated balance sheet at December 31, 2012, other long-term liabilities primarily represent the noncurrent portion of asset retirement obligations, deferred revenues and accrued obligations for pipeline transportation deficiency fees and interest rate derivative instruments.

For additional information regarding our significant contractual obligations, see Note 18 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

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Off-Balance Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, revenues, expenses, results of operations, liquidity, capital expenditures or capital resources.

Related Party Transactions

For information regarding our related party transactions, see Note 15 of the Notes to Consolidated Financial Statements under Part II, Item 8 of this annual report.

Regulation

For information regarding the impact of federal, state or local regulatory measures on our business, see "Regulation" under Part I, Item 1 and 2 of this annual report.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows. In addition, there may be timing differences between amounts we accrue related to property damage expense, amounts we are required to pay in connection with a loss and amounts we subsequently receive from insurance carriers as reimbursements. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not reimbursed by insurance, could reduce our ability to pay distributions to our unitholders and, accordingly, adversely affect the market price of our common units.

Involuntary conversions result from the loss of an asset because of some unforeseen event (e.g., destruction due to fire). Some of these events are insurable, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. EPCO renewed its annual insurance programs during the second quarter of 2012. Under terms of the renewed policies, EPCO's deductibles now range from $5.0 million to $60.0 million depending on the nature of the loss (windstorm or non-windstorm) and the assets involved (onshore or offshore).

We received $30.0 million and $20.0 million of nonrefundable insurance proceeds during the years ended December 31, 2012 and 2011, respectively, attributable to property damage claims we filed in connection with a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. We remain in negotiation with our insurance carriers regarding the overall claim, which is currently projected to be up to $150.0 million. Operating income includes $30.0 million and $4.7 million of gains related to these insurance recoveries during the years ended December 31, 2012 and 2011, respectively. To the extent that additional non-refundable insurance proceeds related to this incident are received, we expect to record gains equal to such proceeds.

For additional information regarding insurance matters, see Note 19 of the Notes to Consolidated Financial Statements under Part II, Item 8 of this annual report.

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

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We assess the risk associated with each of our derivative instrument portfolios using a sensitivity analysis model. This approach measures the change in fair value of the derivative instrument portfolio based on a hypothetical 10% change in the underlying interest rates or quoted market prices on a particular day. In addition to these variables, the fair value of each portfolio is influenced by changes in the notional amounts of the instruments outstanding and the discount rates used to determine the present values. The sensitivity analysis approach does not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming:

§ the derivative instrument functions effectively as a hedge of the underlying risk;

§ the derivative instrument is not closed out in advance of its expected term; and

§ the hedged forecasted transaction occurs within the expected time period.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. If changes in market conditions or exposures warrant, the nature and volume of derivative instruments may change depending on the specific exposures being managed.

See Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our derivative instruments and hedging activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy is a component in controlling our overall cost of capital associated with such borrowings. The composition of our derivative instrument portfolios may change from period-to-period depending on our hedging requirements.

As presented in the tabular data below, each portfolio's estimated fair value at a given date is based on a number of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

Interest rate swaps

Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. The following table summarizes our portfolio of interest rate swaps at December 31, 2012 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes AA	10 fixed-to-floating swaps	$ 750.0	1/2011 to 2/2016	3.2% to 1.3%	Fair value hedge

Undesignated swaps	6 floating-to-fixed swaps	$ 600.0	5/2010 to 7/2014	0.4% to 2.0%	Mark-to-market

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The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value ("FV") of our interest rate swap portfolio at the dates indicated (dollars in millions):

		Interest Rate Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2011	December 31, 2012	January 31, 2013
FV assuming no change in underlying interest rates	Asset	$67.2	$ 28.0	$ 29.1
FV assuming 10% increase in underlying interest rates	Asset	64.4	27.2	28.1
FV assuming 10% decrease in underlying interest rates	Asset	70.0	28.8	30.0

The decrease in fair value of the interest rate swap portfolio since December 31, 2011 is primarily due to the settlement of 11 fixed-to-floating swaps in February 2012, which resulted in gains totaling $37.7 million.

Forward-starting interest rate swaps

Forward starting swaps perform a similar function as traditional interest rate swaps except that they are associated with interest rates underlying anticipated future issuances of debt. The following table summarizes our portfolio of forward starting swaps at December 31, 2012 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Future debt offering	16 forward starting swaps	$1,000.0	3/2013	3.7 %	Cash flow hedge

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our forward starting swap portfolio at the dates indicated (dollars in millions):

		Forward Starting Swap Portfolio Aggregate Fair Value at		
Scenario	Resulting Classification	December 31, 2011	December 31, 2012	January 31, 2013
FV assuming no change in underlying interest rates	Liability	$(290.7)	$ (175.4)	$(153.9)
FV assuming 10% increase in underlying interest rates	Liability	(251.8)	(157.5)	(134.2)
FV assuming 10% decrease in underlying interest rates	Liability	(330.6)	(193.7)	(173.9)

The decrease in fair value of our forward starting swap portfolio since December 31, 2011 is primarily due to the settlement, in connection with the issuance of senior notes, of 17 forward starting swaps having an aggregate notional value of $850.0 million, resulting in cash losses totaling $185.5 million. Although we incurred cash losses upon settlement of our forward starting, we benefited from the exceptionally low interest rate environment during these periods relative to the interest rates in effect at the time we entered into the swaps. The fair value of the remaining forward starting swaps was a liability of $175.4 million at December 31, 2012 and $153.9 million at January 31, 2013.

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Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, refined products and certain petrochemical products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and options contracts. The following table summarizes our portfolio of commodity derivative instruments outstanding at December 31, 2012 (volume measures as noted):

Derivative Purpose	Volume (1) Current (2)	Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Octane enhancement:			
Forecasted purchases of NGLs (MMBbls)	1.3	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	2.8	0.1	Cash flow hedge
Natural gas marketing:			
Forecasted sales of natural gas (Bcf)	3.2	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	16.2	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	2.6	n/a	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	5.5	n/a	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	0.8	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	1.3	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.1	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	3.1	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	6.2	n/a	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	138.6	24.7	Mark-to-market
Refined products risk management activities (MMBbls) (4)	0.8	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	3.9	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.

(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is January 2014, October 2013 and October 2015, respectively.

(3) Current volumes include 39.3 Bcf of physical derivative instruments that are predominantly priced at an index plus a premium or minus a discount related to location differences.

(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

As of February 1, 2013, our predominant commodity hedging strategies were (i) hedging anticipated future contracted sales of NGLs, refined products and crude oil associated with volumes held in inventory and (ii) hedging the fair value of natural gas and refined products in inventory. We did not have any hedges in place with respect to gross margins associated with our future natural gas processing activities. The following information summarizes these hedging strategies:

§

The objective of our NGL, refined products and crude oil sales hedging program is to hedge the margins of anticipated future sales of inventory by locking in sales prices through the use of forward physical sales contracts and commodity derivative instruments.

§ The objective of our natural gas and refined products inventory hedging program is to hedge the fair value of natural gas and refined products currently held in inventory by locking in the sales price of the inventory through the use of commodity derivative instruments.

§ The objective of our natural gas processing strategy is to hedge an amount of gross margin associated with our natural gas processing activities. No such hedges were in place as of February 1, 2013. Management continues to evaluate market conditions to determine the appropriate timing, if at all, of implementing this strategy during 2013. When in use, this strategy uses physical and financial instruments to lock in the purchase prices of natural gas consumed as plant thermal reduction ("PTR") and the sales prices of the related NGL products. This program would consist of (i) the forward sale of a portion of our expected

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equity NGL production at fixed prices for a selected period of time (e.g. through December 31, 2013), which would be achieved through the use of forward physical sales contracts and commodity derivative instruments and (ii) the purchase of commodity derivative instruments having a notional amount based on the volume of natural gas expected to be consumed as PTR in the production of such equity NGL production.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of natural gas necessary to optimize our owned and contractually committed transportation and storage capacity. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur as originally forecasted. As a result of this timing uncertainty, these derivative instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of these assets. The earnings volatility caused by fluctuations in non-cash, mark-to-market earnings cannot be predicted and the impact to earnings could be material.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our natural gas marketing portfolio at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2011	December 31, 2012	January 31, 2013
FV assuming no change in underlying commodity prices	Asset	$22.2	$ 7.6	$ 2.3
FV assuming 10% increase in underlying commodity prices	Asset (Liability)	14.9	3.0	(1.3)
FV assuming 10% decrease in underlying commodity prices	Asset	29.5	12.2	5.9

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our NGL, refined products and petrochemical operations portfolio at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2011	December 31, 2012	January 31, 2013
FV assuming no change in underlying commodity prices	Asset (Liability)	$(12.3)	$ 10.5	$(16.8)
FV assuming 10% increase in underlying commodity prices	Liability	(32.2)	(27.5)	(60.4)
FV assuming 10% decrease in underlying commodity prices	Asset	7.6	48.5	26.8

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our crude oil marketing portfolio at the dates indicated (dollars in millions):

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2011	December 31, 2012	January 31, 2013
FV assuming no change in underlying commodity prices	Liability	$(7.6)	$ (2.0)	$(3.7)
FV assuming 10% increase in underlying commodity prices	Liability	(10.0)	(10.0)	(16.1)
FV assuming 10% decrease in underlying commodity prices	Asset (Liability)	(5.0)	6.1	8.7

Product Purchase Commitments

We have long and short-term purchase commitments for natural gas, NGLs, crude oil, refined products and petrochemicals. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see "Other Items – Contractual Obligations" included under Part II, Item 7 of this annual report.

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Item 8. Financial Statements and Supplementary Data

Our audited consolidated financial statements begin on page F-1 of this annual report.

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

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

As of the end of the period covered by this annual report, our management carried out an evaluation, with the participation of our general partner's chief executive officer, Michael A. Creel (our principal executive officer), and chief financial officer, W. Randall Fowler (our principal financial officer), of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based on this evaluation, as of the end of the period covered by this annual report, Mr. Creel and Mr. Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fourth quarter of 2012, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

The required certifications of Mr. Creel and Mr. Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this annual report (see Exhibits 31 and 32 under Part IV, Item 15 of this annual report).

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL
OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2012

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its chief executive officer and chief financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to the management of Enterprise Products Partners L.P. and the Board of Directors of its general partner regarding the preparation and fair presentation of Enterprise Products Partners L.P.'s published financial statements.

Our management assessed the effectiveness of Enterprise Products Partners L.P.'s internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control—Integrated Framework. This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2012, Enterprise Products Partners L.P.'s internal control over financial reporting is effective based on those criteria.

Our Audit and Conflicts Committee is composed of independent directors who are not officers or employees of our general partner. This committee meets regularly with members of management, internal audit staff and representatives of Deloitte & Touche LLP, our independent registered public accounting firm, to discuss the adequacy of Enterprise Products Partners L.P.'s internal controls over financial reporting, consolidated financial statements and the nature, extent and results of the audit effort. Management reviews all of Enterprise Products Partners L.P.'s significant accounting policies and assumptions affecting its results of operations with the Audit and Conflicts Committee. Both the independent registered public accounting firm and internal auditors have direct access to the Audit and Conflicts Committee without the presence of management.

Deloitte & Touche LLP has issued its attestation report regarding our internal control over financial reporting. That report (see "Report of Independent Registered Public Accounting Firm") is included within this Item 9A.
Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this annual report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in their respective capacities indicated below on March 1, 2013.

/s/ Michael A. Creel	/s/ W. Randall Fowler
Name: Michael A. Creel	Name: W. Randall Fowler
Title: Chief Executive Officer of our general partner, Enterprise Products Holdings LLC	Title: Chief Financial Officer of our general partner, Enterprise Products Holdings LLC

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and the
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the "Company") 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. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting as of December 31, 2012. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's Board of Directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the related statements of consolidated operations, comprehensive income, cash flows, and equity as of and for the year ended December 31, 2012 of the Company and our report dated March 1, 2013 expresses an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2013
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Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Partnership Governance.

Partnership Management

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management, administrative or operating functions. Pursuant to the ASA, these roles are performed by employees of EPCO, which are under the direction of the Board of Directors (the "Board") and executive officers of Enterprise GP. For a description of the ASA, see "Relationship with EPCO and Affiliates—EPCO ASA" under Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

The executive officers of Enterprise GP are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of Enterprise GP. The DD LLC Trustees, through their control of Enterprise GP, have the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of Enterprise GP serves until such member's death, resignation or removal. The employees of EPCO who served as directors of our general partner during 2012 were Ms. Williams and Messrs. Bachmann, Creel, Cunningham, Fowler and Teague.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to Enterprise GP. Whenever possible, Enterprise GP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates. Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.

On February 19, 2013, the Board of Enterprise GP re-elected Mr. Creel as CEO and Mr. Teague as Chief Operating Officer ("COO") and elected Ms. Williams as Chairman of the Board. The Board also approved the creation of a new management oversight group, known as the Office of the Chairman, which consists of the Chairman of the Board, CEO and COO.

In his role as CEO, Mr. Creel remains our principal executive officer and is responsible for, among other things: (i) managing the overall business and financial strategy of Enterprise; (ii) overseeing and providing strategic direction for our businesses, subject to Board approval, in the areas of finance, accounting, human resources, investor relations, risk management and information technology; and (iii) providing required certifications as principal executive officer of Enterprise regarding disclosure controls and procedures and internal control over financial reporting. In his role as COO, Mr. Teague is responsible for, among other things, managing the day-to-day operations of Enterprise and overseeing and providing strategic direction for our businesses, subject to Board approval, in the areas of operations, business development, health and safety. Each of the roles of CEO and COO report directly to the Board. In her role as Chairman of the Board (a non-executive role), Ms. Williams is responsible for, among other things, (i) presiding over and setting the agendas for meetings of the Board, with due consideration for the values and business goals of Enterprise and an effective governance structure; (ii) overseeing the appropriate flow of information to the Board; (iii) acting as a liaison between the Board and senior management;

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and (iv) meeting regularly with the CEO and COO and other Board members to review the strategic direction of Enterprise.

The purpose of the Office of the Chairman is for the group to serve collectively as a liaison to the Board and senior management with respect to, and to provide the Chairman, CEO and COO a venue to discuss, certain matters including: (i) our strategic direction (including business opportunities through organic growth and acquisitions); (ii) the vision, leadership and development of the management team; (iii) business goals and operational performance; and (iv) strategies to preserve our financial strength. In addition, the Office of the Chairman will assist the Board and its Governance Committee in identifying director education opportunities and in determining the size and composition of the Board and recruitment of new members. The Office of the Chairman will also oversee policies that (i) reflect Enterprise's values and business goals and (ii) enhance the effectiveness of our governance structure.

Partnership Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and stakeholders.

A key element of strong governance is having independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with Enterprise GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise GP or us). Based on the foregoing, the Board has affirmatively determined that Messrs. Andress, Barnett, Casey, McMahen, Ross, Smith and Snell are independent directors under the NYSE rules.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain NYSE rules. In particular, we are not required to comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. Currently, seven of the thirteen Board members of Enterprise GP are independent under NYSE rules; however, this composition may not always be in effect. Also, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Enterprise GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Code of Conduct and Ethics and Corporate Governance Guidelines

Enterprise GP has adopted a "Code of Conduct" that applies to its directors, officers and employees. This code sets forth our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance on complying with the code, the reporting of compliance issues, and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our CEO, CFO, principal accounting officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications, and prompt internal reporting of violations of the code (and thus accountability for adherence to the code). Employees are required to periodically certify their understanding and compliance with the Code of Conduct.

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Governance guidelines, together with applicable committee charters, provide the framework for effective governance of our partnership. The Board has adopted the "Governance Guidelines of Enterprise Products Partners," which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibilities of the Audit and Conflicts Committee (the "Audit Committee") and the Governance Committee, the conduct and frequency of Board and committee meetings, management succession plans, director access to management and outside advisors, director compensation, director and executive officer equity ownership, director orientation and continuing education, and annual self-evaluation of the Board. The Board recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary.

Audit Committee

The purpose of the Board's Audit Committee is to address audit and conflicts-related matters. In accordance with NYSE rules and the Securities Exchange Act of 1934, the Board has named three of its members to serve on the Audit Committee. Members of the Audit Committee must have a basic understanding of finance and accounting matters and be able to read and understand fundamental financial statements, and at least one member of the Audit Committee shall have accounting or related financial management expertise. The current members of the Audit Committee are Messrs. McMahen (chairman), Ross and Snell, all of whom are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment. The Board has affirmatively determined that Mr. McMahen satisfies the definition of "audit committee financial expert" as defined in Item 407(d) of Regulation S-K promulgated by the SEC.

The primary responsibilities of the Audit Committee include (i) reviewing potential conflicts of interest, including related party transactions, (ii) monitoring the integrity of our financial reporting process and related systems of internal control, (iii) ensuring our legal and regulatory compliance and that of Enterprise GP, (iv) overseeing the independence and performance of our independent public accountant, (v) approving all services performed by our independent public accountant, (vi) providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board, (vii) encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels, (viii) reviewing areas of potential significant financial risk to our businesses and (ix) approving awards granted under long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the Audit Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the Audit Committee are conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by Enterprise GP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The Audit Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

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Governance Committee

The primary purpose of the Governance Committee is to develop and recommend to the Board a set of governance guidelines applicable to our partnership, to review such guidelines from time to time and to oversee governance matters related to our business, including Board and Committee composition, qualifications of Board candidates, director independence, succession planning and related matters. The Governance Committee also assists in Board oversight of management's establishment and administration of our environmental, health and safety policies, procedures, programs and initiatives, and related matters. In accordance with its charter, the Governance Committee shall be composed of not less than three members, at least a majority of whom shall be independent directors. Currently, the Governance Committee is comprised of four independent directors: Messrs. Andress, Barnett (chairman), Casey and Smith.

Like the Audit Committee, the Governance Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. In addition, the Governance Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Investor Access to Corporate Governance Information

We provide investors access to information relating to our governance procedures and principles, including the Code of Conduct, Governance Guidelines, the Audit and Governance Committee charters, along with other information, through our Internet website, www.enterpriseproducts.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

NYSE Corporate Governance Listing Standards

On March 8, 2012, Mr. Creel, our CEO, certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of March 8, 2012.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. McMahen.

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the Audit Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (877) 888-0002.

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Directors and Executive Officers of Enterprise GP

The following table sets forth the name, age and position of each of the directors and executive officers of Enterprise GP at March 1, 2013. Each executive officer holds the same respective office shown below in the managing member of EPO.

Name	Age	Position with Enterprise GP
Randa Duncan Williams	51	Director and Chairman of the Board
Thurmon M. Andress (1)	79	Director
Richard H. Bachmann	60	Director
E. William Barnett (1,2)	80	Director
Larry J. Casey (1)	80	Director
Michael A. Creel (3)	59	Director and CEO
Dr. Ralph S. Cunningham	72	Director
W. Randall Fowler (3)	56	Director, Executive Vice President and CFO
Charles E. McMahen (4,5)	73	Director
Rex C. Ross (4)	69	Director
Edwin E. Smith (1)	81	Director
Richard S. Snell (4)	70	Director
A. James Teague (3)	67	Director and COO
Lynn L. Bourdon, III (3)	51	Group Senior Vice President
Terrance L. Hurlburt (3)	60	Group Senior Vice President
William Ordemann (3)	53	Group Senior Vice President
Thomas M. Zulim (3)	55	Group Senior Vice President
Bryan F. Bulawa (3)	43	Senior Vice President and Treasurer
Stephanie C. Hildebrandt (3)	48	Senior Vice President, General Counsel and Secretary
Michael J. Knesek (3)	58	Senior Vice President, Controller and Principal Accounting Officer

(1) Member of the Governance Committee
(2) Chairman of the Governance Committee
(3) Executive officer
(4) Member of the Audit Committee
(5) Chairman of the Audit Committee

In addition to the persons listed above, Mr. O.S. Andras serves as an honorary director of Enterprise GP. Mr. Andras' role is solely honorary and does not confer any of the rights, obligations, liabilities or responsibilities of a director of Enterprise GP (including any power or authority to vote on any matters as a director).

The following information presents a brief history of the business experience of our directors and executive officers of Enterprise GP:

Randa Duncan Williams. Ms. Williams was elected as Chairman of the Board of Directors of Enterprise GP in February 2013 and as a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). She served as a director of Holdings GP from May 2007 to November 2010. She was elected Chairman of EPCO in May 2010, having previously served as Group Co-Chairman since 1994. Ms. Williams has served as a director of EPCO since February 1991. Prior to joining EPCO in 1994, Ms. Williams practiced law with the firms Butler & Binion and Brown, Sims, Wise & White. Ms. Williams previously served on the board of directors of Encore Bancshares from July 2007 until July 2012. She currently serves on the board of trustees for numerous charitable organizations. Ms. Williams is the daughter of the late Mr. Dan L. Duncan, our founder.

Thurmon M. Andress. Mr. Andress was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves on its Governance Committee. He served as a director of Holdings GP from November 2006 to November 2010. Mr. Andress serves as the Managing Director-Houston for Breitburn Energy Company L.P. and is a former member of its Board of Directors. In 1990, he founded Andress Oil & Gas Company, serving as its President and CEO until it merged with Breitburn Energy Company L.P. in 1998. In 1982, he founded Bayou Resources, Inc. a publicly traded energy company that was sold in 1987. From 2002 through December 2009, Mr. Andress served as a member of the Board of Directors of Edge Petroleum Corp. (including its Governance and Compensation Committees). In October 2009, Edge Petroleum Corp. filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code and, on December 31, 2009, completed the sale of

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substantially all of its assets to Mariner Energy, Inc. Mr. Andress is currently a member of the National Petroleum Council and the Natural Gas Committee. He also serves on the Board of Governors of Houston for the Independent Petroleum Association of America. In 1993, Mr. Andress was inducted into All American Wildcatter's, a 100-member organization dedicated to American oil and gas explorationists and producers.

Richard H. Bachmann. Mr. Bachmann was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He served as an Executive Vice President of Holdings GP from April 2005 to November 2010 and as a director of Holdings GP from February 2006 to November 2010. He served as Chief Legal Officer and Secretary of Holdings GP from April 2005 to May 2010. Mr. Bachmann served as Executive Vice President and Chief Legal Officer of EPGP from February 1999 until November 2010 and as Secretary of EPGP from November 1999 to November 2010. He previously served as a director of EPGP from June 2000 to January 2004 and from February 2006 to May 2010.

Mr. Bachmann was elected President and CEO of EPCO in May 2010 and has served as a director since January 1999. He previously served as Secretary of EPCO from May 1999 to May 2010 and as a Group Vice Chairman of EPCO from December 2007 to May 2010. Mr. Bachmann served as a director of DEP GP from October 2006 to May 2010 and as President and CEO of DEP GP from October 2006 to April 2010. In November 2006, Mr. Bachmann was appointed as an independent manager of Constellation Energy Partners LLC. Mr. Bachmann also serves as a member of the Audit, Compensation and Nominating and Governance Committees of Constellation Energy Partners LLC and as the Chairman of its Conflicts Committee.

E. William Barnett. Mr. Barnett was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves as Chairman of its Governance Committee. He served as a director of EPGP from March 2005 to November 2010. Mr. Barnett practiced law with Baker Botts L.L.P. from 1958 until his retirement in 2004. In 1984, he became Managing Partner of Baker Botts L.L.P. and continued in that role for 14 years until 1998. He was Senior Counsel to the firm from 1998 until June 2004, when he retired from the firm. Mr. Barnett served as Chairman of the Board of Trustees of Rice University from 1996 to July 2005.

Mr. Barnett is a Life Trustee of The University of Texas Law School Foundation; a director of St. Luke's Episcopal Hospital; a Trustee Emeritus and former Chairman of the Houston Zoo, Inc. (the operating arm of the Houston Zoo); and a Director Emeritus of Baylor College of Medicine. He is a director of Westlake Chemical Corporation (a publicly traded chemical company). From October 2002 until May 2012, Mr. Barnett served as a director of GenOn Energy, Inc. (a publicly traded wholesale electricity generation company) and its predecessors. Mr. Barnett is Chairman of the Advisory Board of the Baker Institute for Public Policy at Rice University and a Director Emeritus and former Chairman of the Greater Houston Partnership.

Larry J. Casey. Mr. Casey was elected a director of Enterprise GP in September 2011 and serves on its Governance Committee. He previously served as a director of DEP GP from October 2006 until September 2011. Mr. Casey has been a private investor managing real estate and personal investments since he retired in 1982 from a career in the energy industry. In 1974, Mr. Casey founded Xcel Products Company, an NGL and petrochemical trading company. Also in 1974, he founded Xral Underground Storage, the first privately owned underground merchant storage facility for NGLs and specialty chemicals at Mont Belvieu, Texas. Mr. Casey sold these companies in 1982.

Michael A. Creel. Mr. Creel was elected CEO and a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as President of Enterprise GP from November 2010 until February 2013. He served as a director of EPGP from February 2006 to November 2010 and President and CEO of EPGP from August 2007 to November 2010. Mr. Creel served as CFO of EPGP from June 2000 to August 2007, and as an Executive Vice President of EPGP from January 2001 to August 2007. Mr. Creel, a Certified Public Accountant, also served as a Senior Vice President of EPGP from November 1999 to January 2001.

Mr. Creel previously served as a director of Holdings GP from October 2009 to May 2010 and as a director of DEP GP from October 2006 to May 2010. He previously served as President, CEO and a director of Holdings GP from August 2005 through August 2007. From October 2006 to August 2007, he served as Executive Vice President and CFO of DEP GP. From October 2005 through December 2009, Mr. Creel served as a director of Edge Petroleum Corporation, a publicly traded oil and natural gas exploration and production company, which filed a

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voluntary petition under Chapter 11 of the U.S. Bankruptcy Code in October 2009 and, on December 31, 2009, completed the sale of substantially all of its assets to Mariner Energy, Inc.

Dr. Ralph S. Cunningham. Dr. Cunningham was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as Chairman of the Board of Enterprise GP from November 2010 until February 2013. Dr. Cunningham served as a director and as the President and CEO of Holdings GP from August 2007 until November 2010. He served as a director of EPGP from February 2006 to May 2010, having previously served as a director of EPGP from April 1998 until March 2005. In addition to these duties, Dr. Cunningham served as Group Executive Vice President and COO of EPGP from December 2005 to August 2007 and Interim President and Interim CEO from June 2007 to August 2007. Dr. Cunningham served as a director of DEP GP from August 2007 to May 2010. He served as Chairman and a director of TEPPCO's general partner from March 2005 until November 2005.

Dr. Cunningham was elected Vice Chairman of EPCO in May 2010 and a director in March 2006, having previously served as Group Vice Chairman of EPCO from December 2007 to May 2010 and as a director of EPCO from 1987 to 1997. He serves as a director, as Chairman of the Board and as a member of each of the Audit Committee and the Nominating and Corporate Governance Committee of TETRA Technologies, Inc. He also serves as a director of Agrium, Inc. In addition, Dr. Cunningham serves as a director, as the Chairman of the Safety, Environment and Responsibility Committee and as a member of each of the Human Resources and Compensation Committee and the Nominating and Corporate Governance Committee of Cenovus Energy Inc. Dr. Cunningham retired in 1997 from CITGO Petroleum Corporation, where he served as President and CEO since 1995. Dr. Cunningham also served as a director of LE GP, LLC (the general partner of Energy Transfer Equity, L.P.) from December 2009 to November 2010.

W. Randall Fowler. Mr. Fowler was elected a director of Enterprise GP in September 2011. He was named an Executive Vice President and the CFO of Enterprise GP in November 2010 (upon consummation of the Holdings Merger), having previously served as Executive Vice President and CFO of EPGP from August 2007 to November 2010. He also served as President and CEO of DEP GP from April 2010 until September 2011 and as Executive Vice President and CFO of DEP GP from August 2007 to April 2010. He served as a director of DEP GP from September 2006 until September 2011.

Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. Mr. Fowler also previously served as a director of EPGP and of Holdings GP from February 2006 to May 2010. Mr. Fowler also served as Senior Vice President and CFO of Holdings GP from August 2005 to August 2007. Mr. Fowler was elected Vice Chairman and CFO of EPCO in May 2010. He previously served as President and CEO of EPCO from December 2007 to May 2010 and as its CFO from April 2005 to December 2007.

Mr. Fowler, a Certified Public Accountant (inactive), joined us as Director of Investor Relations in January 1999. Mr. Fowler also serves as Chairman of the Board of the National Association of Publicly Traded Partnerships. He also serves on the Advisory Board for the College of Business at Louisiana Tech University.

Charles E. McMahen. Mr. McMahen was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and serves as Chairman of its Audit Committee. He served as a director of Holdings GP from August 2005 to November 2010. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and CEO of Compass Banks of Texas from March 1990 until March 1999. Mr. McMahen has served as a director of Compass Bancshares, and its successor, BBVA Compass Bank (a wholly owned subsidiary of BBVA), since 2001. He also serves as a director for the following additional wholly owned subsidiaries of BBVA: (i) BBVA USA Bancshares (a bank holding company for BBVA's North

American banking operations); and (ii) BBVA Compass Bancshares, Inc. (a bank holding company for BBVA Compass Bank). Mr. McMahen serves on the Audit Committee for BBVA Compass Bancshares, Inc. and as Chairman of the Risk Committee for BBVA Compass Bank. Mr. McMahen served as Chairman of the Board of Regents of the University of Houston from September 1998 to August 2000.

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Rex C. Ross. Mr. Ross was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and is a member of its Audit Committee. He served as a director of EPGP from October 2006 until November 2010. Until July 2009, Mr. Ross served as a director of Schlumberger Technology Corporation, the holding company for all Schlumberger Limited assets and entities in the U.S. Prior to his retirement from Schlumberger Limited in May 2004, Mr. Ross held a number of executive management positions during his 11-year career with the company, including President of Schlumberger Oilfield Services North America; President, Schlumberger GeoQuest; and President of SchlumbergerSema North & South America. Mr. Ross also serves on the Board of Directors of Gulfmark Offshore, Inc. (a publicly traded offshore marine services company) and is a member of its Governance & Nominating Committee and its Compensation Committee.

Edwin E. Smith. Mr. Smith was elected a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and is a member of its Governance Committee. He served as a director of Holdings GP from August 2005 to November 2010. Mr. Smith has been a private investor since he retired from Allied Bank of Texas in 1989 after a 31-year career in banking. Mr. Smith previously served as a director of Encore Bancshares from July 2007 until July 2012 and as a director of EPCO from 1987 until 1997.

Richard S. Snell. Mr. Snell, a Certified Public Accountant, was elected a director of Enterprise GP in September 2011 and serves on its Audit Committee. He previously served as a director of DEP GP from January 2010 until September 2011. Mr. Snell also served as a director of TEPPCO's general partner from January 2006 until October 2009. From June 2000 until February 2006, he served as a director of EPGP. He is senior counsel with the law firm of Thompson & Knight LLP, having been with the firm since 2000. Prior to his position with Thompson & Knight LLP, he worked as an attorney for the Snell & Smith, P.C. law firm from its founding in 1993 until 2000.

A. James Teague. Mr. Teague was elected COO and a director of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as an Executive Vice President of Enterprise GP from November 2010 until February 2013. He served as Executive Vice President of EPGP from November 1999 to November 2010 and additionally as a director from July 2008 to November 2010 and as Chief Operating Officer from September 2010 to November 2010. In addition, he served as EPGP's Chief Commercial Officer from July 2008 until September 2010. He served as Executive Vice President and Chief Commercial Officer of DEP GP from July 2008 until September 2011. He previously served as a director of DEP GP from July 2008 to May 2010 and as a director of Holdings GP from October 2009 to May 2010. Mr. Teague joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for Mapco Inc.

Lynn L. Bourdon, III. Mr. Bourdon was elected as Group Senior Vice President, NGL and Natural Gas Marketing in April 2012. He previously served as Senior Vice President (Supply & Marketing) from 2004 to April 2012. From 2001 to 2003, Mr. Bourdon served as Senior Vice President and Chief Commercial Officer with Orion Refining Corporation, which filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code in May 2003. Mr. Bourdon served as a Partner in En*Vantage, Inc. from 1999 to 2001, as Senior Vice President of Commercial Operations for PG&E Gas Transmission from 1997 to 1999 and Vice President, NGL Marketing & Development at its predecessor company, Valero, from 1996 to 1997. Earlier in his career, Mr. Bourdon served 12 years with Dow Chemical Company in the engineering, business and commercial areas.

Terrance L. Hurlburt. Mr. Hurlburt was elected as Group Senior Vice President, Operations and Environmental, Health, Safety & Training in April 2012. He previously served as a Senior Vice President from June 2006 to April 2012 and Vice President and General Manager of Operations from 1992 to June 2006. He joined Enterprise in May 1981 and has held a variety of operations and engineering roles. Prior to joining Enterprise, Mr. Hurlburt served as Assistant Plant Manager for Hill Petroleum's Louisiana Refinery and Chief Technical Advisor for UOP L.L.C.

William Ordemann. Mr. Ordemann was elected as Group Senior Vice President, Unregulated NGLs, Crude and Natural Gas Assets in April 2012 and is responsible for Enterprise's onshore and offshore natural gas and crude oil pipelines, natural gas processing and storage assets, as well as NGL fractionation and storage facilities. He previously served as Executive Vice President of Holdings GP from August 2007 to November 2010 and as

Executive Vice President of Enterprise GP from November 2010 to April 2012. He also served as COO of EPGP from August 2007 until September 2010 and as its Executive Vice President from August 2007 to November 2010. He was also elected an Executive Vice President of DEP GP in August 2007 and served in such role until September 2011. He previously served as a Senior Vice President of EPGP from September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. Mr. Ordemann joined Enterprise in connection with our purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. Prior to joining Enterprise, he was a Vice President of Shell Midstream Enterprises, LLC from January 1997 to February 1998, and Vice President of Tejas Natural Gas Liquids, LLC from February 1998 to September 1999.

Thomas M. Zulim. Mr. Zulim was elected as Group Senior Vice President in April 2012 and is responsible for Enterprise's regulated businesses and refined products businesses. He previously served as a Senior Vice President in the unregulated NGL business and other areas of our operations from July 2008 to April 2012. From March 2006 to July 2008, Mr. Zulim served as Senior Vice President, Human Resources, for both EPGP and EPCO, and served as Vice President, Human Resources, for both EPGP and EPCO from December 2004 to March 2006. He joined EPCO in 1999 as Director of Business Management for the NGL fractionation business. Mr. Zulim came to EPCO from Shell Oil Company where, as an attorney, he practiced labor and employment law nationally for several years before joining Shell Midstream Enterprises in 1996 as Director of Business Development for its natural gas processing and NGL fractionation businesses. Mr. Zulim resumed practicing law with EPCO's legal group in January 2002 until December 2004.

Bryan F. Bulawa. Mr. Bulawa was elected a Senior Vice President and the Treasurer of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). He previously served as Senior Vice President, CFO and Treasurer of DEP GP from April 2010 until September 2011 and a director of DEP GP from February 2011 to September 2011. He also served as Senior Vice President and Treasurer of EPGP and Holdings GP from October 2009 to November 2010, as Senior Vice President and Treasurer of DEP GP from October 2009 to April 2010, and as Vice President and Treasurer of EPGP from July 2007 to October 2009. He has also served as Senior Vice President and Treasurer of EPCO since May 2010. Prior to joining Enterprise, Mr. Bulawa spent 13 years at Scotia Capital, where he last served as director of the firm's U.S. Energy Corporate Finance and Distribution group.

Stephanie C. Hildebrandt. Ms. Hildebrandt was elected a Senior Vice President and the General Counsel of Enterprise GP in November 2010 (upon consummation of the Holdings Merger) and served as Senior Vice President and General Counsel of EPGP and Holdings GP from May 2010 to November 2010. Ms. Hildebrandt served as Senior Vice President, Chief Legal Officer and Secretary of DEP GP from April 2010 until September 2011, having previously served as Vice President and General Counsel of EPGP from October 2009 to May 2010, as Vice President and Deputy General Counsel of EPGP from 2006 to 2009, and as Deputy General Counsel of EPGP from 2004 to 2006. Prior to joining us, Ms. Hildebrandt practiced law for three years at El Paso Corporation and for 12 years at Texaco Inc.

Michael J. Knesek. Mr. Knesek, a Certified Public Accountant, was elected the Senior Vice President, Controller and Principal Accounting Officer of Enterprise GP in November 2010 (upon consummation of the Holdings Merger). From February 2005 to November 2010, Mr. Knesek served as Senior Vice President of EPGP, having previously served as a Vice President of EPGP since August 2000. Mr. Knesek served as the Principal Accounting Officer and Controller of Holdings GP from August 2005 to November 2010 and served in the same capacity for DEP GP from September 2006 to September 2011. He served as the Principal Accounting Officer and Controller of EPGP from August 2000 to November 2010. He also served as Senior Vice President of DEP GP from September 2006 to September 2011. Mr. Knesek has been the Controller of EPCO since 1990 and currently serves as one of its Senior Vice Presidents.

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Director Experience, Qualifications, Attributes and Skills

The following is a brief discussion of the experience, qualifications, attributes or skills that led to the conclusion that each of the following persons should serve as a director of our general partner.

Six of our directors are current employees of EPCO and officers of our general partner or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include: for Ms. Williams, legal and community involvement with numerous charitable organizations, and active involvement in EPCO's businesses, including ownership and management of Enterprise's businesses; for Dr. Cunningham, over 45 years of refined products, chemicals and midstream businesses; for Mr. Bachmann, over 30 years of experience with our midstream assets, including legal, regulatory, contracts and mergers and acquisitions and, for over the last ten years, as a member of Enterprise's executive management team; for Mr. Creel, over 30 years of management experience with midstream assets, for both third parties and Enterprise, including finance and accounting (certified public accountant) and more than seven years of management experience in the financial industry; for Mr. Fowler, over ten years of experience with our midstream assets, including finance, accounting (inactive certified public accountant) and investor public relations and, for over the last seven years, as a member of our executive management team; and for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for Enterprise's businesses.

Our seven outside directors also have significant experience in our industry in a variety of capacities, as well as other qualifications, attributes and skills. These include: for Mr. Andress, oil and gas exploration and production; for Mr. Barnett, legal, regulatory and management skills as a former managing partner of an international law firm; for Mr. Casey, executive management of NGL and petrochemicals trading, and related storage businesses; for Mr. McMahen, banking and finance; for Mr. Ross, executive management of oilfield services businesses; for Mr. Smith, banking and investments; and for Mr. Snell, legal and accounting matters and previous board service for other publicly traded midstream partnerships.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, directors and executive officers of Enterprise GP and any persons holding more than 10% of our common units are required to report their beneficial ownership of common units and any changes in their beneficial ownership levels to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this annual report any failure to file this information within the specified timeframes. All such reporting was done in a timely manner in 2012, except that on February 3, 2012, Mr. Teague filed one late Form 4 reporting one purchase transaction by his spouse that he inadvertently failed to report during 2008.

Item 11. Executive Compensation.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our business. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our management, administrative and operating functions are primarily performed by employees of EPCO pursuant to the ASA. Pursuant to the ASA, we reimburse EPCO for 100% of its compensation costs related to employment of personnel working on our behalf. For information regarding the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Summary Compensation Table

The following table presents total compensation amounts paid, accrued or otherwise expensed by us with respect to the years ended December 31, 2012, 2011 and 2010 for the CEO, the CFO, and the three other most highly compensated executive officers of our general partner. Collectively, these individuals were our "named

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executive officers" for 2012. The compensation amounts presented below include amounts allocated to Holdings prior to the Holdings Merger in November 2010.

Name and Principal Position	Year	Cash Salary ($)	Cash Bonus ($) (1)	Unit Awards ($) (2)	Option Awards ($) (3)	All Other Comp. ($) (4)	Total ($)
Michael A. Creel	2012	$769,000	$1,550,000	$3,738,240	$--	$597,606	$6,654,846
(CEO)	2011	707,275	1,425,000	2,640,354	--	530,461	5,303,090
	2010	607,187	1,046,875	2,091,096	208,905	388,681	4,342,744
W. Randall Fowler	2012	415,097	562,500	1,947,000	--	312,216	3,236,813
(Executive Vice President and CFO)	2011	402,905	562,500	1,442,100	--	287,595	2,695,100
	2010	275,625	262,500	822,885	87,044	166,070	1,614,124
A. James Teague	2012	685,150	1,550,000	3,364,416	--	459,763	6,059,329
(COO)	2011	665,113	1,300,000	1,922,800	--	412,067	4,299,980
	2010	650,000	650,000	1,710,310	174,087	372,446	3,556,843
Lynn L. Bourdon, III	2012	397,500	430,000	1,298,000	--	185,433	2,310,933
(Group Senior Vice President)	2011	387,656	400,000	961,400	--	171,128	1,920,184
	2010	379,219	300,000	451,780	87,044	190,440	1,408,483
William Ordemann	2012	422,900	300,000	1,038,400	--	294,486	2,055,786
(Group Senior Vice President)	2011	414,612	250,000	1,311,000	--	329,170	2,304,782
	2010	406,300	250,000	1,090,726	174,087	283,173	2,204,286

(1) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Cash awards are paid in February of the following year (e.g., the cash awards with respect to 2012 were paid in February 2013).
(2) Amounts represent our estimated share of the aggregate grant date fair value of restricted common unit awards granted during each year presented. For information about assumptions made in the valuation of these awards and limited partner interests, see Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report, the applicable disclosures of which are incorporated by reference into this Item 11.
(3) Amounts represent our estimated share of the aggregate grant date fair value of unit option awards granted during each year presented. For information about assumptions made in the valuation of these awards, see Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report, the applicable disclosures of which are incorporated by reference into this Item 11.
(4) Amounts include (i) contributions in connection with funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards, (iii) the imputed value of life insurance premiums paid on behalf of the officer and (iv) other amounts. See the following table for additional information.

The following table presents the components of "All Other Compensation" for each named executive officer for the year ended December 31, 2012:

Contributions Under Funded, Qualified, Defined Contribution Retirement	Quarterly Distributions Paid On Incentive Plan Awards	Life Insurance Premiums	Other	Total All Other Compensation

	Plans				
Michael A. Creel	$ 27,500	$ 561,524	$ 2,322	$6,260	$ 597,606
W. Randall Fowler	20,625	284,746	1,741	5,104	312,216
A. James Teague	27,500	419,419	6,858	5,986	459,763
William Ordemann	30,000	258,949	1,242	4,295	294,486
Lynn L. Bourdon, III	25,000	155,291	1,242	3,900	185,433

Certain of the named executive officers perform services for other affiliates of EPCO. Under the ASA, the compensation costs of our named executive officers, including those related to equity-based awards, are allocated between us and other affiliates of EPCO based on the estimated amount of time that each officer spends on our consolidated businesses in any fiscal year. These percentages are reassessed at least quarterly.

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The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses, which included Duncan Energy Partners prior to the Duncan Merger in September 2011, and to EPCO and its other affiliates during each of the years presented. As presented in the table, the percentages listed for Enterprise Products Partners have been retrospectively adjusted to include the amount of time each named executive officer devoted to Holdings prior to the Holdings Merger in November 2010.

Named Executive Officer	Year	Enterprise Products Partners	EPCO and other affiliates	Total Time Allocated
Michael A. Creel (CEO)	2012	100%	--	100%
	2011	95%	5%	100%
	2010	84%	16%	100%
W. Randall Fowler (CFO)	2012	75%	25%	100%
	2011	75%	25%	100%
	2010	53%	47%	100%
A. James Teague	2012	100%	--	100%
	2011	100%	--	100%
	2010	100%	--	100%
William Ordemann	2012	100%	--	100%
	2011	100%	--	100%
	2010	100%	--	100%
Lynn L. Bourdon, III	2012	100%	--	100%
	2011	100%	--	100%
	2010	100%	--	100%

Compensation Discussion and Analysis

With respect to our named executive officers, compensation paid or awarded by us for the last three fiscal years reflects only that portion of compensation paid by EPCO and allocated to us pursuant to the ASA, including an allocation of a portion of the cost of equity-based long-term incentive plans of EPCO. The EPCO Trustees control EPCO and provide recommendations with respect to the compensation of our CEO. As discussed further below, the Audit Committee of our general partner was given ultimate decision-making authority with respect to 2012 compensation to be paid to our CEO, and our CEO was given ultimate decision-making authority with respect to 2012 compensation to be paid to our other named executive officers. The following elements of compensation, and EPCO's decisions with respect to determination of payments, are not subject to approvals by the Board or the Audit Committee of our general partner, except in the case of compensation paid to our CEO (as described below). Neither EPCO nor our general partner has a separate compensation committee; however, equity awards granted under EPCO's long-term incentive plans are approved by the Audit Committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other incentives (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objectives of EPCO's compensation program are to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. Our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies we require. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both our partnership and individual levels. With respect to the three years ended December 31, 2012, EPCO's compensation package for named executive officers did not include any elements based on targeted performance-related criteria.

The primary elements of EPCO's compensation program are a combination of annual cash and long-term equity-based incentive compensation. For the three years ended December 31, 2012, the elements of compensation for the named executive officers consisted of annual cash base salary, discretionary annual cash bonus awards,

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awards under long-term incentive arrangements and other compensation, including very limited perquisites.

In order to assist our CEO, EPCO and the Audit Committee with compensation decisions, EPCO's senior vice president of Human Resources formulates preliminary compensation recommendations for each of the named executive officers, including our CEO. With respect to compensation to be paid to our CEO, the EPCO Trustees consider such preliminary recommendation and make revisions, if appropriate. Afterwards, EPCO's senior vice president of Human Resources presents the revised CEO compensation recommendation to the members of the Audit Committee, which consider the recommendation and then make a final determination regarding compensation of our CEO. In making their final determination, the Audit Committee may discuss the recommendation with EPCO's senior vice president of Human Resources, request to discuss the recommendations with EPCO's compensation consultant, and/or retain its own compensation consultant.

With respect to compensation to be paid to Mr. Teague, the CEO and Ms. Williams consider the preliminary recommendation of EPCO's senior vice president of Human Resources and make revisions, if appropriate. The CEO and Ms. Williams make the final determination regarding Mr. Teague's compensation.

With respect to compensation to be paid to the remaining named executive officers other than our CEO and Mr. Teague, the CEO and Mr. Teague consider the preliminary recommendations of EPCO's senior vice president of Human Resources and make revisions, if appropriate. The CEO makes a final determination regarding compensation of these named executive officers.

In making these compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by a third-party compensation consultant. In 2011, EPCO engaged Meridian Compensation Partners, LLC (the "Consultant") to complete a detailed review of executive compensation relative to our industry. In connection with this review, the Consultant provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors and other large companies. The market data for industry competitors included information from Atmos Energy Corporation; CenterPoint Energy, Inc.; CMS Energy Corporation; Constellation Energy Group, Inc.; Dominion Resources, Inc.; El Paso Corporation; Enbridge Energy Partners, L.P.; Energy Transfer Partners, L.P.; NiSource Inc.; NuStar Energy L.P.; ONEOK, Inc.; Plains All American Pipeline, L.P.; Spectra Energy Corp.; The Williams Companies, Inc.; and TransCanada Corporation. The market data for other large companies included 51 entities across multiple industries ranging in revenue size from $80 billion to $15 billion, including well-known companies such as The Procter & Gamble Company; The Home Depot, Inc.; Archer Daniels Midland Company; Target Corporation; and The Boeing Company, among others.

Neither we, nor EPCO, which engages the Consultant, are aware of the specific data of the companies included in the Consultant's proprietary database for specific positions. EPCO uses the information provided in the Consultant's analysis to gauge whether compensation levels reported by the Consultant and the general ranges of compensation for EPCO employees in similar positions are comparable, but that comparison is only a factor taken into consideration and may or may not impact compensation of our named executive officers, for which our Audit Committee (in the case of our CEO's compensation) or our CEO (in the case of compensation to be paid to our other named executive officers) has the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

The Audit Committee, our CEO and EPCO do not use any formula or specific performance-based criteria in determining the compensation of our named executive officers for services they perform for us; rather, the Audit Committee or our CEO (as applicable) and EPCO determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that the Audit Committee or our

CEO (as applicable) may take into account in making the case-by-case compensation determinations include total value of all elements of compensation and the appropriate balance of internal pay equity among executive officers. The Audit Committee, our CEO and EPCO also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are subjective and discretionary and, as noted above, subject to the ultimate decision-making authority of the Audit Committee or the CEO (as applicable), except for equity awards under EPCO's long-term incentive plans, as discussed below.

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We believe that the absence of specific performance-based criteria associated with our cash compensation and equity awards, and the long-term nature of our equity awards, has the effect of discouraging excessive risk taking by our executive officers in order to reach certain targets. Further, the practice of making compensation decisions on a case-by-case basis permits consideration of flexible criteria, including current overall market conditions.

Changes in the base salaries of our named executive officers during the three years ending December 31, 2012 were largely budget-driven and made consistent relative to increases in the base salaries of our other executive officers.

The discretionary cash bonus awards paid to each of our named executive officers were determined by consultation, as appropriate, among the EPCO Trustees, our CEO and EPCO's senior vice president of Human Resources, subject to final determination by the Audit Committee (in the case of our CEO's cash bonus awards) and our CEO (in the case of cash bonus awards to be paid to our other named executive officers). These cash bonus awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the named executive officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the named executive officers may perform services. It is EPCO's general policy to pay these awards in February of the following year. The discretionary cash bonuses reflected the Audit Committee's (with respect to our CEO) and our CEO's (with respect to the other named executive officers) general consideration of our financial performance for those periods, without any weight or formula given to any specific financial performance measures, as well as their subjective judgment of each named executive officer's general contributions in connection with our performance, again without any weight or formula given to any specific individual contribution or accomplishments. The levels of cash bonuses were also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

Since 2010, the awards granted under EPCO's long-term incentive plans to our named executive officers were determined by consultation among the EPCO Trustees, our CEO and EPCO's senior vice president of Human Resources, and were approved by the Audit Committee. The levels of EPCO's long-term incentive plan awards to our named executive officers during the last three years also reflected the Audit Committee's and our CEO's (with respect to the other named executive officers) general consideration of our financial performance for those periods, without any weight or formula given to any specific financial performance measures, as well as their subjective judgment of each named executive officer's general contributions in connection with our performance, again without any weight or formula given to any specific individual contribution or accomplishments. The levels of long-term incentive awards were also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

EPCO expects to continue its policy of paying for limited perquisites attributable to our named executive officers. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2012.

In the fourth quarter of 2010, EPCO entered into retention agreements with each of the named executive officers to reinforce and encourage the continued dedication of such officers to EPCO and us as a member of our executive management team and to assure that we and EPCO will have the services of the executives in the foreseeable future. Pursuant to the retention agreements, Messrs. Creel, Fowler, Teague, Ordemann and Bourdon will be entitled to a cash retention payment of $10 million, $5 million, $10 million, $2.5 million and $2.5 million, respectively, less applicable withholding taxes (as applicable to each person, the "Retention Payment") following the completion of 48 months of continuous employment with EPCO from the effective date of each retention agreement (the "Retention Period"). We record an allocated portion of such costs based on the approximate amount of time each officer spends on our consolidated business activities. The effective date of the retention agreements for Mr. Creel, Mr. Fowler and

Mr. Teague was December 1, 2010. The effective date of the retention agreements for Mr. Ordemann and Mr. Bourdon was October 1, 2010.

Notwithstanding the required Retention Period, if at any time between 24 months and 48 months after December 1, 2010 (i.e., the period of continuous employment from December 1, 2010 until such time being referred to as the "Performance Period"), Mr. Teague designates a candidate to serve as COO of Enterprise GP and such candidate is determined by the Audit Committee to be satisfactory and is hired by EPCO, then Mr. Teague will be entitled to a cash performance payment of the greater of (a) $6 million or (b) $10 million times (i) the number of months of Mr. Teague's Performance Period, divided by (ii) 48 (the "Performance Payment"). Pursuant to his retention agreement, Mr. Teague is eligible to earn and receive either the Performance Payment or the Retention Payment, but not both.

Notwithstanding the Retention Period described above, each of the named executive officers will receive, or in the event of his death, his designated beneficiary will receive, unless otherwise required by law, his applicable Retention Payment in the event of an involuntary termination of his employment prior to the end of his Retention Period for specified reasons, including death, disability or termination of his employment by EPCO other than for "cause" (as defined in the applicable retention agreement) in connection with his job elimination, a business reorganization, or a sale of EPCO or us. The Retention Payment is payable in full within 30 days of such qualifying termination. In the event the named executive officer is paid his Retention Payment in connection with an involuntary termination as described above, he agrees that, for a period equal to the lesser of (i) 18 months after the date of the event which gives rise to the Retention Payment or (ii) the remainder of the Retention Period (as if the retention agreement were in full force and effect for the full Retention Period), he will not solicit or induce, either directly or indirectly, any of our employees to cease employment with EPCO.

Any Retention Payment or Performance Payment (with respect to Mr. Teague) is in addition to any discretionary incentive compensation that EPCO or any of its affiliates may, in its sole discretion, grant or have in place from time to time.

Although the retention agreements, restricted common unit awards and unit option awards are entered into with EPCO, all or a portion of the compensation related to these agreements may be allocated to us in accordance with the ASA by and among EPCO, us and the other parties thereto.

We believe that each of the base salary, discretionary cash bonus awards, long-term incentive awards and retention agreements, as applicable, fit the overall compensation objectives of us and of EPCO and are designed to avoid risks that are likely to conflict with our risk management policies.

Grants of Plan-Based Awards in Fiscal Year 2012

The following table presents information concerning each 2012 grant of a plan-based award to a named executive officer for which we will be allocated our pro rata share of the related expense under the ASA.

		Estimated Future Payouts Under Equity Incentive Plan Awards			Exercise or Base Price of Option Awards	Grant Date Fair Value of Unit and Option Awards
Name	Grant Date	Threshold (#)	Target (#)	Maximum (#)	($/Unit)	($) (1)
Restricted common unit awards:						
Michael A. Creel (CEO)	2/21/12	--	72,000	--	--	$3,738,240
W. Randall Fowler (CFO)	2/21/12	--	50,000	--	--	1,947,000

A. James Teague	2/21/12	--	64,800	--	--	3,364,416
William Ordemann	2/21/12	--	20,000	--	--	1,038,400
Lynn L. Bourdon, III	2/21/12	--	25,000	--	--	1,298,000

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the average percentage of time each named executive officer spent on our consolidated businesses during 2012. Based on current allocations, we estimate that the consolidated compensation expense we record for each named executive officer with respect to these awards will approximate these grant date fair value amounts over the vesting period. The closing price of our common units on February 21, 2012 was $51.92 per unit.

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The restricted common unit awards granted to the named executive officers during 2012 were made under the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan"). This plan provides for incentive awards to EPCO's key employees who perform management, administrative or operational functions for us or our affiliates.

No option awards were granted during 2012.

Grant date fair value amounts presented in the preceding table are based on certain assumptions and considerations made by management. See Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our fair value assumptions made in connection with equity-based compensation.

Summary of Long-Term Incentive Arrangements Underlying 2012 Award Grants

Awards granted under the 1998 Plan may be in the form of unit options, restricted common units, phantom units and distribution equivalent rights ("DERs"). As of December 31, 2012, no phantom unit awards, unit appreciation rights ("UARs") or associated DERs have been granted under EPCO's incentive compensation plans to the named executive officers.

Restricted common unit awards allow recipients to acquire our common units (at no cost to the recipient apart from service or other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Restricted common unit grants generally vest at a rate of 25% per year beginning one year after the grant date. The fair value of restricted common units is based on the market price per unit of our common units on the date of grant. For financial statement purposes, compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures. Each recipient is also entitled to quarterly cash distributions equal to the product of the number of restricted common units outstanding for the participant and the quarterly cash distribution per common unit paid by us.

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Equity Awards Outstanding at December 31, 2012

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2012.

		Option Awards				Unit Awards	
Name	Vesting Date	Number of Units Underlying Options Exercisable (#)	Number of Units Underlying Options Unexercisable (#)	Option Exercise Price ($/Unit)	Option Expiration Date	Number of Units That Have Not Vested (#) (2)	Market Value of Units That Have Not Vested ($) (3)
Restricted common unit awards:							
Michael A. Creel (CEO)	Various (1)	--	--	--	--	210,800	$ 10,556,864
W. Randall Fowler (CFO)	Various (1)	--	--	--	--	142,500	7,136,400
A. James Teague	Various (1)	--	--	--	--	161,700	8,097,936
William Ordemann	Various (1)	--	--	--	--	89,400	4,477,152
Lynn L. Bourdon, III	Various (1)	--	--	--	--	61,000	3,054,880
Unit option awards:							
Michael A. Creel (CEO):							
May 22, 2008 option grant (4)	5/22/12	--	90,000	$ 30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	75,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	90,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	90,000	32.27	12/31/15	--	--
W. Randall Fowler (CFO):							
May 22, 2008 option grant (4)	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	52,500	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	60,000	32.27	12/31/15	--	--
A. James Teague:							
May 22, 2008 option grant (4)	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	60,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	60,000	32.27	12/31/15	--	--
William Ordemann:							
May 22, 2008 option grant (4)	5/22/12	--	60,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	45,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	60,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	60,000	32.27	12/31/15	--	--
Lynn L. Bourdon, III:							
May 22, 2008 option grant (4)	5/22/12	--	30,000	30.93	12/31/13	--	--
February 19, 2009 option grant	2/19/13	--	30,000	22.06	12/31/14	--	--
May 6, 2009 option grant	5/06/13	--	30,000	24.92	12/31/14	--	--
February 23, 2010 option grant	2/23/14	--	30,000	32.27	12/31/15	--	--

(1) Of the 665,400 non-vested restricted common unit awards presented in the table, 331,550 vest in 2013, 167,050 vest in 2014, 108,850 vest in 2015 and 57,950 vest in 2016.

(2) Amounts represent the total number of restricted common unit awards outstanding for each named executive officer.
(3) Amounts derived by multiplying the total number of restricted common unit awards outstanding for each named executive officer by the closing price of our common units at December 31, 2012 (the last trading day of 2012) of $50.08 per unit.
(4) These option grants are exercisable beginning in February 2013.

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options. These unit option awards are denominated in our common units. When issued, the exercise price of each unit option award may be no less than the market price of our common units on the date of grant. In general, unit option awards have a vesting period of four years from the date of grant and expire at the end of the calendar year following the year of vesting (e.g., an option vesting on May 22, 2012 will expire on December 31, 2013). However, unit option awards only become exercisable at certain times during the calendar year following the year in which they vest (typically the months of February, May, August and November).

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Option Exercises and Units Vested

The following table presents the exercise of unit options by and vesting of restricted common units to our named executive officers during the year ended December 31, 2012.

	Option Awards		Unit Awards	
Name	Number of Units Acquired on Exercise (#)	Gross Value Realized on Exercise ($) (1)	Number of Units Acquired on Vesting (#)	Gross Value Realized on Vesting ($) (2)
Michael A. Creel (CEO):				
Option awards	16,528	$1,149,000		
Restricted common unit awards			76,150	$3,851,838
W. Randall Fowler (CFO):				
Option awards	12,594	861,750		
Restricted common unit awards			51,850	2,621,468
A. James Teague:				
Option awards	16,523	1,149,000		
Restricted common unit awards			52,350	2,647,103
William Ordemann:				
Option awards	8,463	585,000		
Restricted common unit awards			44,050	2,219,707
Lynn L. Bourdon, III:				
Option awards	8,873	632,100		
Restricted common unit awards			17,600	892,195

(1) Amount determined by multiplying the number of units acquired on exercise of the options by the difference between the closing price of our common units on the date of exercise and the exercise price.
(2) Amount determined for restricted common unit awards by multiplying the number of restricted common unit awards that vested during 2012 by the closing price of our common units on the date of vesting.

Potential Payments Upon Termination or Change-in-Control

Our named executive officers do not have any employment agreements that call for payment of termination or severance benefits or that provide for any payments in the event of a change in control of our general partner.

EPCO has entered into retention agreements with each of the named executive officers, which are described under "Compensation Discussion and Analysis" within this Item 11. Under these agreements, each such person will receive, or in the event of his death, his designated beneficiary will receive, unless otherwise required by law, his applicable Retention Payment (set forth previously) in the event of an involuntary termination of his employment prior to the end of his Retention Period for specified reasons, including death, disability or termination of his employment by EPCO other than for "cause" (as defined in each retention agreement) in connection with his job elimination, a business reorganization or a sale of EPCO or our partnership.

Vesting of restricted unit awards and option awards under the 1998 Plan and the Amended and Restated 2008 Enterprise Products Long-Term Incentive Plan ("2008 Plan") are subject to acceleration upon a qualifying termination, including termination after a change of control of our general partner. Qualifying termination under such awards generally means a termination as an employee of EPCO or an affiliated group member (i) upon death, (ii) a qualifying long-term disability, (iii) a qualifying retirement, or (iv) within one year after a change of control (as defined), other than a termination for cause (as defined) or termination by such person that is not a qualifying termination for good reason (as defined). A change of control under these award agreements is generally defined to mean that Dan L. Duncan, his widow, descendants, heirs and/or legatees and/or distributees of Dan L. Duncan's estate, and/or trusts (including, without limitation, one or more voting trusts) established for the benefit of his widow, descendants, heirs and/or legatees and/or distributees, collectively, cease, directly or indirectly, to control our general partner. Mr. Duncan passed away in March 2010.

As of December 31, 2012, the estimated market value of unvested unit option awards that could be realized in connection with an accelerated vesting for a qualifying termination (calculated as the difference between the

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exercise prices of the underlying options and closing price of our common units on December 31, 2012 of $50.08 per unit, but without reflecting any allocation of compensation to other entities under the ASA), would have been the following for each of the named executive officers:

	Accelerated Option Value
Michael A. Creel (CEO)	$7,692,300
W. Randall Fowler (CFO)	5,198,250
A. James Teague	5,408,400
William Ordemann	4,988,100
Lynn L. Bourdon, III	2,704,200

Although the retention agreements, restricted unit awards and unit option awards are entered into with EPCO, all or an allocated portion of the compensation related to these agreements may be charged to us in accordance with the ASA.

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our named executive officers. Rather, under the ASA, we reimburse EPCO for the compensation of our executive officers. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO, our CEO and the Audit Committee of our general partner.

In light of the foregoing, the Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth above and determined that it be included in this annual report for the year ended December 31, 2012.

Submitted by: Randa Duncan Williams
Thurmon M. Andress
Richard H. Bachmann
E. William Barnett
Larry J. Casey
Michael A. Creel
Dr. Ralph S. Cunningham
W. Randall Fowler
Charles E. McMahen
Rex C. Ross
Edwin E. Smith
Richard S. Snell
A. James Teague

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Securities Exchange Act, as amended, that incorporate future filings, including this annual report, in whole or in part, the foregoing Compensation Committee Report shall not be incorporated by reference into any such filings.

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of our general partner served as members of the compensation committee of another entity that has or had an executive officer who served as a member of our Board during 2012. As previously noted, we do not have a separate compensation committee. As described in Compensation Discussion and

Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO, our CEO and the Audit Committee of our general partner.

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Director Compensation

Neither we nor our general partner provide any additional compensation to employees of EPCO who serve as directors of our general partner.

The independent directors of our general partner are compensated as follows: (i) each receives a $75,000 annual cash retainer; (ii) if the individual serves as chairman of a committee of the Board, then he receives an additional $15,000 in cash annually; (iii) each receives a meeting fee of $1,500 in cash for each meeting of the Board attended; (iv) each receives a meeting fee of $1,500 in cash for each meeting of a duly appointed committee of the Board attended, provided that he is duly elected or appointed to the committee; and (v) each receives an annual grant of our common units having a fair market value, based on the closing price of such security on the trading day immediately preceding the date of grant, of approximately $75,000.

The following table presents information regarding compensation paid to the independent directors of our general partner during the year ended December 31, 2012:

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($)	All Other Compensation ($)	Total ($)
Thurmon M. Andress	$96,000	$74,453	$ --	$170,453
E. William Barnett (1)	111,000	74,453	--	185,453
Larry J. Casey	96,000	74,453	--	170,453
Charles E. McMahen (2)	117,000	74,453	--	191,453
Rex C. Ross	102,000	74,453	--	176,453
Edwin E. Smith	96,000	74,453	--	170,453
Richard S. Snell	102,000	74,453	--	176,453

(1) Mr. Barnett serves as chairman of the Governance Committee.
(2) Mr. McMahen serves as chairman of the Audit Committee.

As an honorary director, O.S. Andras receives $20,000 in cash annually for his services.

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

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of January 31, 2013, regarding each person known by Enterprise GP to beneficially own more than 5% of our limited partner units:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Randa Duncan Williams 1100 Louisiana Street, 10th Floor Houston, Texas 77002	334,610,450 (1)	37.2%
Class B units	Randa Duncan Williams 1100 Louisiana Street, 10th Floor Houston, Texas 77002	4,520,431	100%

(1) For a detailed listing of the ownership amounts that comprise Ms. Williams' total beneficial ownership of our common units, see the table presented in the following section, "Security Ownership of Management," within this Item 12.

Security Ownership of Management

The following table sets forth certain information regarding the beneficial ownership of our common units as of January 31, 2013 by (i) our named executive officers; (ii) the current directors of Enterprise GP; and (iii) the current directors and executive officers (including named executive officers) of Enterprise GP as a group. All beneficial ownership information has been furnished by the respective directors and executive officers. Each person has sole voting and dispositive power over the securities shown unless indicated otherwise. The beneficial ownership amounts of certain individuals include options to acquire our common units that became exercisable in February 2013.

Ms. Williams is a DD LLC Trustee, an EPCO Trustee, an independent co-executor of the estate of Dan L. Duncan and a beneficiary of the estate. Ms. Williams is also currently Chairman and a Director of EPCO and Chairman of the Board and a Director of our general partner. Ms. Williams disclaims beneficial ownership of the limited partner units beneficially owned by the EPCO Trustees, the DD LLC Trustees and Mr. Duncan's estate except to the extent of her voting and dispositive interests in such units.

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Name of Beneficial Owner	Amount and Nature Of Beneficial Ownership	Percent of Class
Randa Duncan Williams:		
Units controlled by DD LLC Voting Trust		
Through DFI GP Holdings L.P.	40,844,206	4.5%
Through Dan Duncan LLC	20,881	*
Units controlled by EPCO Voting Trust:		
Through EPCO	523,306	*
Through EPCO Investments, LLC	15,241,517	1.7%
Through Duncan Family Interests, Inc.	257,909,910	28.7%
Through EPCO Holdings, Inc.	7,839,629	*
Units controlled by estate of Dan L. Duncan (1)	10,111,436	1.1%
Units controlled by Alkek and Williams, Ltd.	163,000	*
Units controlled by family trusts (2)	1,950,000	*
Units owned personally (3)	6,565	*
Total for Randa Duncan Williams	334,610,450	37.2%
Michael A. Creel (CEO) (4,5)	778,446	*
W. Randall Fowler (CFO) (4,6)	607,842	*
A. James Teague (4,7)	876,182	*
William Ordemann (4,8)	452,587	*
Lynn L. Bourdon, III (4,9)	305,085	*
Thurmon M. Andress (10)	36,278	*
Richard H. Bachmann (11)	662,687	*
E. William Barnett	21,113	*
Larry J. Casey (12)	23,613	*
Dr. Ralph S. Cunningham (13)	511,555	*
Charles E. McMahen	40,085	*
Rex C. Ross (14)	64,524	*
Edwin E. Smith	188,378	*
Richard S. Snell	11,797	*
All current directors and executive officers of Enterprise GP, as a group (20 individuals in total) (15)	340,204,258	37.8%

* Represents a beneficial ownership of less than 1% of class

(1) The number of common units presented for the estate of Dan L. Duncan includes common units held of record by DD Securities LLC.

(2) The number of common units presented for Ms. Williams includes 1,512,500 common units held by family trusts for which she is the trustee but has disclaimed beneficial ownership.

(3) The number of common units presented for Ms. Williams includes 4,545 common units held of record by her spouse and 2,020 common units held of record jointly with her spouse.

(4) These individuals are the named executive officers for 2012.

(5) The number of common units presented for Mr. Creel includes 90,000 common unit options that are exercisable beginning in February 2013.

(6) The number of common units presented for Mr. Fowler includes (i) 250,000 common units held by a family limited partnership (for which he has disclaimed beneficial ownership except to the extent of his pecuniary interest) and (ii) 60,000 common unit options that are exercisable beginning in February 2013.
(7) The number of common units presented for Mr. Teague includes (i) 189,409 common units held by an immediate family member, (ii) 26,500 common units held by a family trust and (iii) 60,000 common unit options that are exercisable beginning in February 2013.
(8) The number of common units presented for Mr. Ordemann includes 60,000 common unit options that are exercisable beginning in February 2013.
(9) The number of common units presented for Mr. Bourdon includes (i) 30,000 common unit options that are exercisable beginning in February 2013 and (ii) 600 common units held by immediate family members.
(10) The number of common units presented for Mr. Andress includes (i) 1,200 common units held by an immediate family member, (ii) 15,532 common units held by a family partnership and (iii) 712 common units held by family trusts.
(11) The number of common units presented for Mr. Bachmann includes (i) 15,738 common units held by family trusts, (ii) 2,231 common units held by an immediate family member and (iii) 60,000 common unit options that are exercisable beginning in February 2013.
(12) The number of common units presented for Mr. Casey includes 26 common units held by an immediate family member.
(13) The number of common units presented for Dr. Cunningham includes (i) 305,506 common units held by a family limited partnership (for which he has disclaimed beneficial ownership except to the extent of his pecuniary interest), (ii) 23 common units held by the general partner of such family limited partnership and (iii) 60,000 common unit options that are exercisable beginning in February 2013.
(14) The number of common units presented for Mr. Ross includes 53,852 common units held by family trusts.
(15) Cumulatively, this group's beneficial ownership amount includes 525,000 common unit options that are exercisable beginning in February 2013.

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Privately-held affiliates of EPCO (together with their respective subsidiaries) have pledged up to 62,500,000 of our common units that they own as security under such affiliates' credit facilities. These credit facilities include customary provisions regarding potential events of default. As a result, a change in ownership of these units could result if an event of default ultimately occurred.

Equity Ownership Guidelines

In order to further align the interests and actions of our general partner's directors and executive officers with our long-term interests and those of our general partner and other unitholders, the Board has adopted and approved certain equity ownership guidelines for our general partner's directors and executive officers. Under these guidelines:

§ each non-management director of our general partner is required to own our common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such non-management director's aggregate annual cash retainer for service on the Board for the most recently completed calendar year; and

§ each executive officer of our general partner is required to own our common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such executive officer's aggregate annual base salary for the most recently completed calendar year.

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Securities Authorized for Issuance Under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2012 regarding the long-term incentive plans of EPCO under which our common units are authorized for issuance. For additional information regarding our equity-based compensation, see Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Common Unit Options (a)	Weighted-Average Exercise Price of Outstanding Common Unit Options	Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a))