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.

ENTERPRISE PRODUCTS PARTNERS L.P.
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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.

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.

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- 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.

Seasonality. 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.

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

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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

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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

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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

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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.

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 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

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;

§ 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 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