ENTERPRISE PRODUCTS PARTNERS L P
Form 10-K
March 02, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Section I.01
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, 2014

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 No

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 No

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.

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 Accelerated filer Non-accelerated filer Smaller reporting company

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

The aggregate market value of the partnership's common units held by non-affiliates at June 30, 2014 (the last business day of the registrant's most recently completed second fiscal quarter) was $46.77 billion based on a closing price on that date of $39.15 per common unit on the New York Stock Exchange Composite ticker tape. There were 1,937,592,017 common units outstanding at January 31, 2015.

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 privately held Texas limited liability company.

The membership interests of Dan Duncan LLC are owned 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; and (iii) Richard H. Bachmann. 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 privately held Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

In addition to owning our general partner, EPCO and its privately held affiliates owned approximately 35.3% of our limited partner interests at December 31, 2014.

References to "Oiltanking" mean Oiltanking Partners L.P. References to "Oiltanking GP" mean OTLP GP, LLC, the general partner of Oiltanking. On October 1, 2014, we acquired Oiltanking GP and the related incentive distribution rights ("IDRs"), 15,899,802 common units and 38,899,802 subordinated units of Oiltanking from Oiltanking Holding Americas, Inc. and its affiliates (collectively, "OTA").

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, 2014 (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, petrochemicals and refined products.

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 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 (including liquefied petroleum gas or "LPG");

§ crude oil gathering, transportation, storage and terminals;

§ offshore production platforms;

§ petrochemical and refined products transportation, storage and terminals, and related 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 51,300 miles of onshore and offshore pipelines; 225 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, 22 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and export terminals, a refined products export terminal, 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.

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, 2015, there were approximately 6,900 EPCO personnel who spend all or a substantial portion of their time engaged in our business. For additional information regarding the ASA, see "EPCO ASA" under Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

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Business Strategy

Our business strategies are to:

- capitalize on expected increases in the production of natural gas, NGLs and crude oil from development activities in various domestic production basins (e.g., the Rocky Mountains, Mid-Continent, Northeast, U.S. Gulf Coast and deepwater Gulf of Mexico), including associated shale plays such as the Barnett, Eagle Ford, Permian, 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 provide processing, throughput or feedstock volumes for growth capital projects or purchase such projects' end products.

As noted above, part of our business strategy involves expansion through growth capital projects. See Part II, Item 7 of this annual report for information regarding our capital spending program.

Commercial and Liquidity Outlook for 2015

For information regarding our commercial and liquidity outlook for the year ending December 31, 2015, see "General Outlook for 2015" included under Part II, Item 7 of this annual report.

Major Customer Information

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2014 was Shell Oil Company and its affiliates (collectively, "Shell"), which accounted for 8.5% of our consolidated revenues in 2014. Our largest non-affiliated customer for 2013 and 2012 was BP p.l.c. and its affiliates, which accounted for 9.0% and 9.5%, respectively of our consolidated revenues in these years. 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.

Acquisition of Oiltanking Partners, L.P.

On October 1, 2014, we acquired Oiltanking GP and the related incentive distribution rights, 15,899,802 common units and 38,899,802 subordinated units of Oiltanking from OTA. We paid total consideration of approximately $4.4 billion to OTA comprised of $2.21 billion in cash and 54,807,352 Enterprise common units for these ownership interests and rights. We also paid $228.3 million to assume the outstanding loans, including related accrued interest, owed by Oiltanking or its subsidiaries to OTA. Collectively, these transactions are referred to as "Step 1" of the Oiltanking acquisition. We funded the cash consideration for the Step 1 transactions using borrowings under our new $1.5 Billion 364-Day Credit Agreement, proceeds from the sale of short-term notes under our commercial paper program and cash on hand.

Oiltanking owns marine terminals located on the Houston Ship Channel and at the Port of Beaumont with a total of 12 ship and barge docks and approximately 26 MMBbls of crude oil and petroleum products storage capacity.

Oiltanking's marine terminal on the Houston Ship Channel is connected by pipeline to our Mont Belvieu, Texas complex and is integral to our growing LPG export, crude oil storage and octane enhancement and propylene businesses. Our Enterprise Crude Houston ("ECHO") facility is also connected to Oiltanking's system. We have had a strategic relationship and enjoyed mutual growth with Oiltanking and its predecessors since 1983. The combination of our legacy midstream assets and Oiltanking's access to waterborne markets and crude oil and

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petroleum products storage assets extends and broadens our midstream energy services business. We believe this combination benefits our producing and consuming customers by enhancing their respective access to supplies, domestic and international markets, and storage.

Following Step 1 of the Oiltanking acquisition, but not part of Step 2 of the acquisition, on November 17, 2014, the 38,899,802 Oiltanking subordinated units held by Enterprise automatically converted into an equal number of Oiltanking common units pursuant to the terms of the Oiltanking partnership agreement. Following this conversion, Enterprise owned 54,799,604 Oiltanking common units, or approximately 65.9% of Oiltanking's outstanding common units.

As a second step of the Oiltanking acquisition (separately negotiated by the conflicts committee of Oiltanking's general partner on behalf of Oiltanking), we entered into an Agreement and Plan of Merger (the "merger agreement") with Oiltanking on November 11, 2014 that provided for the following:

§ the merger of a wholly owned subsidiary of Enterprise with and into Oiltanking, with Oiltanking surviving the merger as a wholly owned subsidiary of Enterprise (the "Oiltanking Merger"); and

§ all outstanding common units of Oiltanking at the effective time of the merger held by Oiltanking's public unitholders (which consist of Oiltanking unitholders other than Enterprise and its subsidiaries) to be cancelled and converted into Enterprise common units based on an exchange ratio of 1.30 Enterprise common units for each Oiltanking common unit.

In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including Enterprise's ownership interests representing approximately 65.9% of Oiltanking's outstanding common units) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,557 Enterprise common units were issued to Oiltanking's former public unitholders. After taking into account the aggregate value of consideration issued and paid in the Oiltanking acquisition, our total cost to acquire Oiltanking was approximately $5.9 billion.

In connection with Step 1 of the transaction, we entered into a Liquidity Option Agreement with OTA and Marquard & Bahls ("M&B"), an affiliate of OTA. Pursuant to the Liquidity Option Agreement, we granted M&B the option (the "Liquidity Option") to sell to Enterprise 100% of the issued and outstanding capital stock of OTA (the "Option Securities") at any time within a 90-day period commencing on February 1, 2020. At that time, OTA's only significant asset would be the Enterprise common units it received in Step 1, to the extent that such common units are not sold by M&B prior to the Liquidity Option exercise date. If this put option is exercised, the aggregate consideration to be paid by us for the Option Securities would equal 100% of the then-current fair market value of the OTA-owned Enterprise common units at the closing of the transactions contemplated under the Liquidity Option Agreement. The fair market value would be determined by multiplying the number of Enterprise common units owned by OTA at the time of exercise by the volume-weighted sales price per unit of Enterprise common units as reported by the NYSE (or other national securities exchange, as applicable) for the ten (10) consecutive trading days preceding the exercise. The consideration paid may be in the form of newly issued Enterprise common units, cash or any mix thereof, as determined solely by us. The Liquidity Option Agreement contains indemnification by M&B for certain specified liabilities of OTA following the closing of any exercise of the Liquidity Option, and certain conditions to closing.
If a defined "Trigger Event" occurs, the Liquidity Option may be exercised earlier within a 135-day period following notice of such event. The aggregate consideration to be paid by us for the Option Securities in connection with an exercise of the option due to a Trigger Event will be solely cash, determined in the same manner as the price otherwise payable upon the exercise of the Liquidity Option in the absence of a Trigger Event.

See "Recent Issuance of Unregistered Securities" under Part II, Item 5 for information regarding a registration rights agreement we entered into in connection with the 54,807,352 common units issued as consideration in Step 1 of the Oiltanking acquisition.

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OTA is wholly owned by an affiliate of Oiltanking GmbH, an independent storage provider for crude oil, refined products, liquid chemicals and gases headquartered in Hamburg, Germany. Dr. F. Christian Flach, managing director of Oiltanking GmbH and former chairman of the board of Oiltanking, was named as a director of our general partner in connection with our acquisition of Oiltanking. For additional information regarding Dr. Flach, see Part III, Item 10 of this annual report.

As a result of our acquisition of Oiltanking GP, we began consolidating the financial statements of Oiltanking and its general partner on October 1, 2014. This business combination was accounted for using the acquisition method of accounting. Acquisition accounting requires us to allocate the cost of a business combination to the assets acquired and liabilities assumed based on their estimated fair values on the transaction date. For information regarding our accounting for this business combination, see Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena Duces Tecum from the Federal Trade Commission requesting specified information relating to the Oiltanking acquisition. We are in the process of complying with the requests and are cooperating with the investigation. Based on the limited information that Enterprise has at this time, we are unable to predict the outcome of the investigation.

Business Segments

The following sections provide an overview of our business segments, including information regarding principal products produced and/or 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.

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 asset 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 participate in supply and demand opportunities as a supplemental source of gross operating margin 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 are influenced by current and forward market prices for the products bought and sold.

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. Factors that can affect the demand for our products and services include domestic and international economic conditions, the market price and demand for energy, the cost to develop natural gas and crude oil reserves in the U.S., state and federal regulation, and the cost and availability of capital to energy companies to invest in upstream exploration and production activities. For information regarding such 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 "Regulatory Matters" within this Part I, Item 1 and 2 discussion.

For management's discussion and analysis of our results of operations, liquidity and capital resources and capital spending program, 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 19,300 miles of NGL pipelines; NGL and related product storage facilities; and 15 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 as fuel by industrial and residential consumers. Ethane is primarily used in the petrochemical industry as a feedstock in the production of ethylene, 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. LPG, which is propane, butane, or a mixture thereof, is used as a feedstock in ethylene plant operations and for power generation and heating purposes.

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 and impurities. Once the natural gas is processed and NGLs and impurities are 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 as components of a natural gas stream.

Once mixed 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 NGLs we obtain through our processing arrangements (referred to as our "equity NGL production" volumes) or purchase directly from third parties are used in our NGL marketing activities to meet contractual requirements or sold in 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.

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. As of December 31, 2014, we estimate that the terms of approximately 45% of our current portfolio of natural gas processing contracts (based on natural gas inlet volumes) were entirely fee-based, with an additional 19% of this portfolio including a combination of fee-based and commodity-based terms. The terms of the remaining 36% of our portfolio of natural gas processing contracts were 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

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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, 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 plant thermal reduction.

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. 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.

The following table presents selected information regarding our natural gas processing facilities at February 1, 2015:

| 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% | | 1.80 | 1.80 |
| Pioneer (two facilities) | Wyoming | 100.0% | | 1.35 | 1.35 |
| Yoakum | Texas | 100.0% | | 1.05 | 1.05 |
| Chaco | New Mexico | 100.0% | | 0.60 | 0.60 |
| North Terrebonne | Louisiana | 55.9% | (2) | 0.53 | 0.95 |
| Neptune | Louisiana | 66.0% | (2) | 0.43 | 0.65 |
| Pascagoula | Mississippi | 40.0% | (2) | 0.40 | 1.50 |
| Sea Robin | Louisiana | 50.6% | (2) | 0.33 | 0.65 |
| Thompsonville | Texas | 100.0% | | 0.33 | 0.33 |
| Shoup | Texas | 100.0% | | 0.28 | 0.28 |
| Gilmore | Texas | 100.0% | | 0.25 | 0.25 |
| Armstrong | Texas | 100.0% | | 0.25 | 0.25 |
| Toca | Louisiana | 71.9% | (2) | 0.22 | 0.30 |
| San Martin | Texas | 100.0% | | 0.20 | 0.20 |
| Indian Basin | New Mexico | 42.4% | (2) | 0.18 | 0.18 |
| 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 |
| Chaparral | New Mexico | 100.0% | | 0.04 | 0.04 |

| | | |
|---|---|---|
| Total | 9.02 | 11.92 |

(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 contractual arrangements with joint owners.
(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").

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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 59.1%, 54.1% and 55.9% during the years ended December 31, 2014, 2013 and 2012, respectively.

In March 2013, we completed the third and final phase (or "train") at our Yoakum natural gas processing facility. In the aggregate, the three processing trains at Yoakum can process up to a combined 1.05 Bcf/d of natural gas and extract approximately 144 MBPD of mixed NGLs. The Yoakum facility processes natural gas produced primarily from the Eagle Ford Shale and is linked by pipeline to our Wilson natural gas storage facility and various downstream markets. Mixed NGLs extracted at the Yoakum plant are transported to our NGL fractionation and storage complex at Mont Belvieu, Texas.

In September 2014, we announced plans to construct a new cryogenic natural gas processing plant in Eddy County, New Mexico and associated natural gas and NGL pipeline infrastructure to facilitate growing production of NGL-rich natural gas in the Delaware Basin, a prolific production area in West Texas and southern New Mexico. These assets are expected to begin operations in the first quarter of 2016. The South Eddy natural gas processing plant is expected to have an initial capacity of 200 MMcf/d of natural gas, with the potential for future expansions. Upon completion, this will bring our total natural gas processing plant capacity in the Delaware Basin to approximately 400 MMcf/d.

To supply the new South Eddy plant, we plan to construct approximately 80 miles of natural gas gathering pipelines to complement our existing 1,500 miles of natural gas gathering pipelines located in the Delaware Basin. We also expect to build a 75-mile, 12-inch diameter NGL pipeline to transport NGLs from the South Eddy plant to our Hobbs NGL fractionation and storage facility located in Gaines County, Texas. As a result of multiple pipeline connections at our Hobbs facility, shippers will have access to our NGL fractionation and storage complex at Mont Belvieu, Texas. Additionally, we plan to deliver residue gas from the South Eddy plant through new interconnections with existing third party pipelines located in the vicinity of the plant.

Our NGL marketing activities generate revenues from merchant activities such as term and spot sales of NGLs, which 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 NGL merchant sales are primarily dependent on the difference 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 adjustments for factors such as location, timing or NGL product quality. Market prices for 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. For a discussion of our commodity hedging program, see Part II, Item 7A of this annual report.

Our NGL export facilities play an integral role in meeting the needs of customers wanting to export NGLs from the U.S. Gulf Coast. Our NGL marketing group assists customers in meeting their export requirements (e.g., through long-term sales contracts with take or pay provisions and/or exchanges of NGLs with export customers) and arranging access to our export facility. We expect export-related sales volumes to increase over the next three years due to existing customer commitments and expanded capacity at our Houston Ship Channel NGL export facility.

Our NGL marketing activities utilize a fleet of approximately 740 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 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 and ethane to destinations along our various pipeline systems.

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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 transportation services. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies, including the Federal Energy Regulatory Commission ("FERC"), or contractual arrangements. Typically, pipeline transportation revenue is recognized when volumes are transported and delivered. However, under certain NGL pipeline transportation agreements (e.g., those associated with committed shippers on our Texas Express Pipeline, Front Range Pipeline, ATEX and Aegis Ethane Pipeline), customers are required to ship a minimum volume over an agreed-upon period. These arrangements typically entail the shipper paying a transportation fee based on a minimum volume commitment, with a provision that allows the shipper to make-up any volume shortfalls over the agreed-upon period (referred to as shipper "make-up rights"). Revenue attributable to shipper make-up rights is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired (typically a one year contractual period), or when the pipeline is otherwise released from its transportation service performance obligation.

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.

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The following table presents selected information regarding our NGL pipelines at February 1, 2015:

| Description of Asset | Location(s) | Our Ownership Interest | | Length (Miles) |
|---|---|---|---|---|
| NGL pipelines: | | | | |
| Mid-America Pipeline System (1) | Midwest and Western U.S. | 100.0% | | 8,065 |
| South Texas NGL Pipeline System | Texas | 100.0% | | 1,918 |
| Dixie Pipeline (1) | South and Southeastern U.S. | 100.0% | | 1,306 |
| Seminole Pipeline (1) | Texas | 100.0% | | 1,249 |
| ATEX (1) | Texas to Midwest and Northeast U.S. | 100.0% | | 1,205 |
| Chaparral NGL System (1) | Texas, New Mexico | 100.0% | | 1,002 |
| Louisiana Pipeline System | Louisiana | 100.0% | | 953 |
| Texas Express Pipeline (1) | Texas | 35.0% | (2) | 593 |
| Skelly-Belvieu Pipeline (1) | Texas, Oklahoma | 50.0% | (3) | 572 |
| Front Range Pipeline (1) | Colorado, Oklahoma, Texas | 33.3% | (4) | 447 |
| Promix NGL Gathering System | Louisiana | 50.0% | (5) | 351 |
| Rio Grande Pipeline (1) | Texas | 70.0% | (6) | 249 |
| Houston Ship Channel | Texas | 100.0% | | 224 |
| Lou-Tex NGL Pipeline (1) | Texas, Louisiana | 100.0% | | 206 |
| Panola Pipeline | Texas | 55.0% | (7) | 188 |
| Tri-States NGL Pipeline (1) | Alabama, Mississippi, Louisiana | 83.3% | (8) | 167 |
| Chunchula Pipeline (1) | Alabama, Mississippi | 100.0% | | 147 |
| Texas Express Gathering System | Texas, Oklahoma | 45.0% | (9) | 116 |
| Aegis Ethane Pipeline (1) | Texas, Louisiana | 100.0% | | 60 |
| Others (six systems) (9) | Various | Various | (11) | 311 |
| Total | | | | 19,329 |

(1) Interstate and/or intrastate transportation services provided by these liquids pipelines are regulated by governmental agencies.
(2) Our ownership interest in the Texas Express Pipeline is held indirectly through our equity method investment in Texas Express Pipeline LLC.
(3) Our ownership interest in the Skelly-Belvieu Pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C.
(4) Our ownership interest in the Front Range Pipeline is held indirectly through our equity method investment in Front Range Pipeline LLC.
(5) 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").
(6) We own a 70% consolidated interest in the Rio Grande Pipeline through our majority owned subsidiary, Rio Grande Pipeline Company.
(7) On January 1, 2015, we formed a joint venture and assigned a 45% interest in Panola Pipeline Company, LLC ("Panola") to third parties. Prior to January 1, 2015, Panola was a wholly owned subsidiary of ours.
(8) 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.
(9) Our ownership interest in the Texas Express Gathering System is held indirectly through our equity method investment in Texas Express Gathering LLC ("Texas Express Gathering").
(10) Includes our Belle Rose and Wilprise pipelines located in the coastal regions of Louisiana; two Port Arthur pipelines located in southeast Texas; our San Jacinto pipeline

located in East Texas; and a pipeline in Colorado associated with our Meeker facility. Transportation services provided by the Belle Rose and Wilprise pipelines are regulated by governmental agencies.

(11) 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 "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of liquids pipelines, including tariffs charged for transportation services.

The maximum number of barrels per day that our NGL pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our NGL pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 2,636 MBPD, 2,540 MBPD and 2,327 MBPD during the years ended December 31, 2014, 2013 and 2012, respectively.

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The following information describes each of our principal NGL pipelines. We operate our NGL pipelines with the exception of the Texas Express Gathering System and Tri-States NGL Pipeline.

- § The Mid-America Pipeline System is an NGL pipeline system consisting of four primary segments: the 3,147-mile Rocky Mountain pipeline, the 2,136-mile Conway North pipeline, the 624-mile Ethane-Propane Mix pipeline and the 2,158-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 NGL 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. 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 the Conway and Hobbs hubs. At the Hobbs NGL hub, the Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionation and storage facility. The Mid-America Pipeline System is also connected to 18 non-regulated NGL terminals that we own and operate.

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

In January 2014, we completed an expansion project involving the Rocky Mountain pipeline of our Mid-America Pipeline System. This expansion project involved looping 265 miles of the Rocky Mountain pipeline, as well as related pump station modifications, which increased transportation capacity on the pipeline from approximately 275 MBPD to 350 MBPD. This expansion project was built to accommodate growing natural gas and NGL production from major supply basins in Colorado, Utah and Wyoming.

- § The South Texas NGL Pipeline System is a network of NGL gathering and transportation pipelines located in South Texas. This system gathers and transports mixed NGLs from natural gas processing plants in South Texas (owned by us or third parties) to our NGL fractionators in South Texas and Mont Belvieu, Texas. In addition, this 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. This includes using parts of our South Texas NGL Pipeline System in connection with our Aegis Ethane Pipeline to extend our planned ethane header system from Mont Belvieu, Texas to Corpus Christi, Texas. The South Texas NGL Pipeline System also connects our South Texas NGL fractionators with our storage facility in Mont Belvieu, Texas.

We placed 188 miles of pipelines belonging to this system into service in phases between May 2012 and March 2013. This included a 168-mile segment that transports mixed NGLs from our Yoakum natural gas processing plant to our Mont Belvieu NGL fractionation and storage complex. In addition, we placed into service a 173-mile NGL pipeline that extends from our Yoakum facility to a third party natural gas processing plant located in LaSalle County, Texas, and provides NGL pipeline takeaway capacity for additional third party gas plants. This pipeline extension commenced operations in June 2013.

- § The Dixie Pipeline extends from southeast Texas 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: Alabama, Georgia, Louisiana, Mississippi, North Carolina, South Carolina and Texas, and is connected to eight non-regulated propane terminals that we own and operate.

- 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

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originating on the Mid-America Pipeline System are the primary source of throughput for the Seminole Pipeline.

§ The ATEX, or Appalachia-to-Texas Express, pipeline primarily transports ethane in southbound service from four NGL fractionation plants located in Ohio, Pennsylvania and West Virginia to our Mont Belvieu storage complex. The ethane extracted by these fractionation facilities originates from the Marcellus and Utica Shale production areas. ATEX began commercial operations in January 2014 and operates in nine states: Arkansas, Illinois, Indiana, Louisiana, Missouri, Ohio, Pennsylvania, Texas and West Virginia. In addition to newly constructed pipeline segments, significant portions of ATEX consist of pipeline segments that were formerly used in refined products transportation service by our TE Products Pipeline. Initial throughput capacity for ATEX is 125 MBPD, which could be expanded to approximately 265 MBPD with certain system modifications.

ATEX terminates at our Mont Belvieu storage complex, which includes approximately 111 MMBbls of NGL and petroleum liquid storage capacity and an extensive pipeline distribution system. With the addition of our Aegis Ethane Pipeline, we will link Marcellus and Utica Shale-produced ethane to existing ethylene production facilities along the U.S. Gulf Coast and provide supply security to support construction of new third party ethylene plants currently planned at Texas and Louisiana petrochemical facilities. Also, since our Houston region pipeline network supports our export terminals on the Houston Ship Channel, ethane volumes delivered to Mont Belvieu via ATEX may contribute to future exports of U.S.-produced ethane to international markets.

§ The Chaparral NGL System transports mixed NGLs from natural gas processing plants in West Texas and New Mexico to Mont Belvieu, Texas. This system consists of the 822-mile Chaparral pipeline and the 180-mile Quanah pipeline. Interstate and intrastate transportation services provided by the Chaparral pipeline are regulated; however, transportation services provided by the Quanah pipeline are not.

§ 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 related storage facilities are located.

§ The Texas Express Pipeline extends from Skellytown, Texas to our NGL fractionation and storage complex at Mont Belvieu, Texas. This pipeline commenced operations in November 2013. Mixed NGLs from the Rocky Mountains, Permian Basin and Mid-Continent regions are delivered to the Texas Express Pipeline via an interconnect with our Mid-America Pipeline System near Skellytown. The Texas Express Pipeline also transports mixed NGLs from two gathering systems owned by Texas Express Gathering to Mont Belvieu. In addition, mixed NGLs from the Denver-Julesburg supply basin are transported to the Texas Express Pipeline using the Front Range Pipeline, which commenced operations in February 2014. Throughput capacity for the Texas Express Pipeline is 280 MBPD, which could be expanded to approximately 400 MBPD with certain system modifications.

§ 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 Front Range Pipeline, which commenced operations in February 2014, transports mixed NGLs from natural gas processing plants located in the Denver-Julesburg Basin in Colorado to an interconnect with our Texas Express Pipeline and Mid-America Pipeline System at Skellytown, Texas. Throughput capacity for the Front Range Pipeline is 150 MBPD, which could be expanded to approximately 230 MBPD with certain system modifications.

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

§ 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 Houston Ship Channel pipeline system connects our Mont Belvieu complex to our Houston Ship Channel import/export terminals and various third party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel.

§ The Panola Pipeline transports mixed NGLs from points near Carthage, Texas to Mont Belvieu and supports the Haynesville and Cotton Valley oil and gas production areas. In January 2015, we announced an expansion project involving the Panola Pipeline consisting of the installation of 60 miles of new pipeline, as well as pumps and other related equipment designed to increase the system's throughput capacity by 50 MBPD to approximately 100 MBPD. The incremental capacity is expected to be available in the first quarter of 2016.

§ The Lou-Tex NGL Pipeline system transports mixed NGLs, purity NGL products and refinery grade propylene between the Louisiana and Texas markets.

§ The Tri-States NGL Pipeline transports mixed NGLs from Mobile Bay, Alabama to points near Kenner, Louisiana and is operated by BP.

§ The Chunchula Pipeline transports propane and butane from the Alabama-Florida border to our storage facility at Petal, Mississippi.

§ The Texas Express Gathering System is comprised of two NGL gathering systems that deliver volumes to the Texas Express Pipeline. These gathering systems commenced operations in November 2013. The Elk City gathering system is currently comprised of 55 miles of pipeline and gathers mixed NGLs from natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma. The North Texas gathering system currently comprises 61 miles of pipeline and gathers mixed NGLs from natural gas processing plants in the Barnett Shale production area in North Texas. Enbridge serves as operator of these two NGL gathering systems.

§ The Aegis Ethane Pipeline (or "Aegis") represents a key component of our planned ethane header system stretching from Corpus Christi, Texas to the Mississippi River in Louisiana. In September 2014, we completed the first segment, or 60 miles, of the planned 270-mile Aegis pipeline. As a result of this completion, we commenced ethane deliveries between our Mont Belvieu storage complex and customers in Beaumont, Texas. After taking into account existing South Texas midstream infrastructure and completion of the first segment of Aegis, our ethane header system is now in service from Corpus Christi to Beaumont. The remainder of Aegis will be completed in two phases: the next segment between Beaumont and Lake Charles, Louisiana is expected to be completed in the third quarter of 2015 and the final segment from Lake Charles to the Mississippi River is expected to be completed by the end of 2015. Aegis is expected to have a throughput capacity of up to 425 MBPD.

NGL and related product storage facilities. We use both underground storage caverns (or wells) and above ground storage tanks to store mixed NGLs and purity NGL, petrochemical and related 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 that customer excess storage fees. 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.

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The following table presents selected information regarding our NGL and related product storage assets at February 1, 2015:

| Storage Capacity by State | Net Usable Storage Capacity (MMBbls) |
|---|---|
| Texas | 125.9 |
| Louisiana | 14.0 |
| Kansas | 8.6 |
| Mississippi | 5.1 |
| Others (1) | 7.2 |
| Total (2) | 160.8 |

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

(2) Our aggregate net usable storage capacity includes 17.8 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 another leased facility in Kansas. 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 related products for industrial customers located along the upper Texas Gulf Coast. This facility has an aggregate usable storage capacity of approximately 111 MMBbls, a brine system with approximately 20 MMBbls of above-ground brine storage pit capacity and four wells available for brine production.

Houston Ship Channel NGL export dock and related operations. We own a marine terminal located on the Houston Ship Channel having the capability to load cargoes of fully refrigerated, low-ethane propane and/or butane (collectively referred to as LPG) onto multiple tanker vessels simultaneously. Currently, the terminal has a loading capability of up to 7.5 MMBbls per month of LPG. Our LPG export services continue to benefit from increased NGL supplies produced from domestic shale plays such as the Eagle Ford Shale and international demand for propane as a feedstock in ethylene plant operations and for power generation and heating purposes. Our average LPG loading volumes at this export terminal were 248 MBPD, 231 MBPD and 131 MBPD during the years ended December 31, 2014, 2013 and 2012, respectively.

In September 2013, we announced an expansion project at this export terminal that is expected to increase its ability to load cargoes from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. This expansion project is expected to be completed in the first quarter of 2015. In January 2014, we announced a further expansion of this export terminal that is expected to increase its loading capability from approximately 9.0 MMBbls per month to in excess of 16.0 MMBbls per month by the end of 2015. We expect our maximum loading capacity at this terminal to be approximately 27,000 barrels per hour once the expansion projects, which are supported by long-term LPG export agreements, are completed.

We also own an NGL import facility located at the same terminal as our Houston Ship Channel LPG export terminal. This import facility can offload NGLs from tanker vessels at rates up to 14,000 barrels per hour depending on the product. Our NGL import volumes were minimal during each of the years ended December 31, 2014, 2013 and 2012.

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Historically, we leased the site that our Houston Ship Channel NGL import and LPG export facility is located on from Oiltanking. Due to completion of the Oiltanking Merger in February 2015, we now own these facilities.

The results of operations from our export and import terminals are primarily dependent upon the volume handled and the associated fees we charge for such services. Revenue from NGL import and LPG export terminaling activities is recorded in the period services are provided. Customers, which include our NGL marketing business, are typically billed a fee per unit of volume loaded or unloaded.

Houston Ship Channel ethane export dock. In April 2014, we announced plans to construct a fully refrigerated ethane export facility on the Houston Ship Channel. The new facility, which is located near La Porte, Texas, is expected to have an aggregate loading rate of approximately 10,000 barrels per hour and is supported by long-term contracts. The ethane export facility will be integrated with our Mont Belvieu NGL fractionation and storage complex. We believe that our integrated NGL system offers supply assurance and diversification for the ethane export facility. We expect the ethane export facility to begin operations in the third quarter of 2016.

Our ethane export facility will provide new markets for domestically-produced ethane, and will assist U.S. producers in increasing their associated production of natural gas and crude oil. We estimate that U.S. ethane production capacity currently exceeds U.S. demand by 400 to 500 MBPD and could exceed demand by up to 700 MBPD by 2020, after considering the estimated incremental demand from new ethylene facilities that have been announced.

NGL fractionation. We own or have interests in 15 NGL fractionators, which separate mixed NGL streams into purity NGL products, located in Texas and Louisiana. 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 to NGL fractionation facilities by NGL pipelines and, to a lesser extent, by railcar and truck.

Mixed NGLs extracted by domestic natural gas processing plants (e.g., by our Yoakum plant) 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 natural gas processing plants located along the Gulf Coast and in the Rocky Mountains and Mid-Continent regions, 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 also support our NGL marketing activities. We typically earn revenues from NGL fractionation under fee-based arrangements. 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, 2015:

| Description of Asset | Location | Our Ownership Interest | Net Plant Capacity (MBPD) (1) | Total Plant Capacity (MBPD) |
|---|---|---|---|---|
| NGL fractionation facilities: | | | | |
| Mont Belvieu | Texas | Various (2) | 572 | 670 |
| Shoup and Armstrong | Texas | 100.0% | 98 | 98 |
| Hobbs | Texas | 100.0% | 75 | 75 |
| Norco | Louisiana | 100.0% | 75 | 75 |
| Promix | Louisiana | 50.0% (3) | 73 | 145 |
| BRF | Louisiana | 32.2% (4) | 19 | 60 |
| Tebone | Louisiana | 55.9% (5) | 17 | 30 |
| Total | | | 929 | 1,153 |

(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 contractual arrangements with joint owners.
(2) Six of our eight Mont Belvieu NGL fractionators are held jointly with third parties. We proportionately consolidate a 75% undivided interest in three units and substantially all of a fourth unit. We own a 75% consolidated equity interest in NGL fractionators seven and eight through our majority owned subsidiary, Enterprise EF78 LLC. The remaining two units, NGL fractionators five and six are wholly owned by us.
(3) Our ownership interest in the Promix fractionator is held indirectly through our equity method investment in Promix.
(4) Our ownership interest in the BRF fractionator is held indirectly through our equity method investment in Baton Rouge Fractionators LLC ("BRF").
(5) We proportionately consolidate our undivided 55.9% interest in the Tebone fractionator.

On a weighted-average basis, overall utilization rates for our NGL fractionators were 89.4%, 88.5% and 91.9% during the years ended December 31, 2014, 2013 and 2012, respectively. We operate all of our NGL fractionators.

The following information describes each of our principal NGL fractionators:

§ Our Mont Belvieu NGL fractionation complex is located at Mont Belvieu, Texas, which is a key hub of the global NGL industry. Our Mont Belvieu NGL fractionation assets process mixed NGLs from several major NGL supply basins in North America, including the Eagle Ford Shale, Rocky Mountains, Mid-Continent, Permian Basin and San Juan Basin. Our Mont Belvieu NGL fractionation complex features connectivity to our network of NGL supply and distribution pipelines, approximately 111 MMBbls of salt dome storage capacity, and access to international markets through our existing LPG export facility and future ethane export facility.

We placed the seventh and eighth NGL fractionators at our Mont Belvieu complex into operation in September 2013 and November 2013, respectively. These two new fractionators (each with 85 MBPD of fractionation capacity) were built to handle NGL production from domestic shale plays, including the Eagle Ford Shale in South Texas and other supply basins in the Rocky Mountains and Mid-Continent regions.

In September 2014, we announced plans to build a ninth NGL fractionator adjacent to our complex in Mont Belvieu, Texas. If constructed, the ninth fractionator is expected to have a capacity of 85 MBPD. We have secured the required permits and emission credits for the ninth and a possible, similarly-sized tenth NGL fractionator at Mont Belvieu. We are evaluating the timing of these projects in light of current business conditions.

§ 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 serves NGL producers in West Texas, New Mexico, California and northern Mexico. The Hobbs fractionator receives mixed NGLs from several major supply basins, including the Mid-Continent, Permian Basin, San Juan Basin and Rocky Mountains. The facility is located at the interconnect of our Mid-America Pipeline System and Seminole Pipeline, thus providing us the operating flexibility to supply both the nation's largest NGL hub at Mont Belvieu 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 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 our Neptune and Pascagoula facilities. In addition to the Promix NGL Gathering System, Promix owns three NGL storage caverns and leases a fourth NGL storage cavern. Promix also owns a barge loading facility.

- 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 seasonal variation. Our NGL marketing activities utilize 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 purposes) 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.

Seasonality has little impact on our LPG export terminal operations; however, historical NGL import volumes have been higher during the spring and summer 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 primarily 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.

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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 fractionator to receive a customer's mixed NGLs and store and distribute the resulting 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 19,300 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 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 revenue contracts, there are typically two components: (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, 2015:

| 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) | 8,173 | 6,640 | 12.9 |
| Acadian Gas System (1) | Louisiana | 100.0% | (3) | 1,324 | 3,100 | 1.3 |
| Jonah Gathering System | Wyoming | 100.0% | | 786 | 2,360 | -- |
| San Juan Gathering System | New Mexico, Colorado | 100.0% | | 6,126 | 1,750 | -- |
| Piceance Basin Gathering System | Colorado | 100.0% | | 189 | 1,600 | -- |
| White River Hub (4) | Colorado | 50.0% | (5) | 10 | 1,500 | -- |
| Haynesville Gathering System | Louisiana, Texas | 100.0% | | 358 | 1,300 | -- |
| Fairplay Gathering System | Texas | 100.0% | (6) | 275 | 285 | -- |
| Carlsbad Gathering System | Texas, New Mexico | 100.0% | | 920 | 220 | -- |
| Indian Springs Gathering System (7) | Texas | 80.0% | (8) | 174 | 160 | -- |
| Delmita Gathering System | Texas | 100.0% | | 199 | 145 | -- |
| South Texas Gathering System | Texas | 100.0% | | 510 | 143 | -- |
| Big Thicket Gathering System (7) | Texas | 100.0% | | 256 | 60 | -- |
| Total | | | | 19,300 | | 14.2 |

(1) Transportation services provided by these systems are regulated by governmental agencies.
(2) Of the 8,173 miles comprising the Texas Intrastate System, we lease 240 miles from a third party. We proportionately consolidate our undivided interests, which range from 22% to 80%, in 1,459 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 transportation service provided by this facility is 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) The Fairplay Gathering System includes approximately 52 miles of pipeline held under an operating lease.
(7) Intrastate transportation services provided by the Indian Springs Gathering System and Big Thicket Gathering System are regulated by governmental agencies.
(8) We proportionately consolidate our 80% undivided interest in the Indian Springs Gathering System.

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

On a weighted-average basis, overall utilization rates for our onshore natural gas pipelines were approximately 60.5%, 65.2% and 67.7% during the years ended December 31, 2014, 2013 and 2012, respectively. These 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 segments of the Texas Intrastate System, we operate our onshore natural gas pipelines and storage facilities.

- The Texas Intrastate System is comprised of the 6,833-mile Enterprise Texas pipeline system, the 629-mile Channel pipeline system, the 584-mile Waha gathering system and the 127-mile TPC Offshore gathering 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

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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 584-mile Cypress pipeline, 444-mile Acadian pipeline, 270-mile Haynesville Extension pipeline 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 local gas distribution companies, electric generation plants and industrial customers located primarily in the Baton Rouge/New Orleans/Mississippi River corridor.

- 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 System consists of the 215-mile State Line gathering system, the 73-mile Southeast Mansfield gathering system and the 70-mile Southeast Stanley gathering system. The Haynesville Gathering System gathers 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 regional markets, including (through an interconnect with the Haynesville Extension pipeline) markets served by our Acadian Gas System.

- The Fairplay Gathering System gathers natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations within Panola and Rusk Counties in East Texas for delivery to regional markets.

- 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, Carlsbad and Indian Basin plants, as well as delivery into the El Paso Natural Gas and Transwestern pipelines.

In addition to our natural gas pipelines, we own a natural gas treating facility (the "Central Treating Facility") located in Rio Blanco County, Colorado. This facility can treat up to 200 MMcf/d of natural gas and serves Exxon Mobil Corporation's ("ExxonMobil") producing properties in the Piceance Basin. Natural gas delivered to the Central Treating Facility by ExxonMobil is treated to remove impurities and transported to our Meeker gas plant for further processing.

Natural gas marketing activities. Our natural gas marketing activities generate revenues from the sale and delivery to local gas distribution companies and other customers of natural gas 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

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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 Acadian Gas and Texas Intrastate Systems. 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 natural gas price index. This index may fluctuate based on a variety of factors, including changes in 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 as well as standalone natural gas marketing and trading firms. 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 5,400 miles of onshore crude oil pipelines, crude oil storage terminals located in Oklahoma and Texas, and our crude oil marketing activities. This business also includes a fleet of approximately 560 tractor-trailer tank trucks, the majority of which we lease and operate, that are used to transport crude oil for us and third parties.

Onshore crude oil pipelines. Our onshore crude oil pipeline systems gather and transport crude oil 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. Typically, revenue associated with these arrangements is recognized when volumes have been transported and delivered; however, under certain of our crude oil pipeline transportation agreements (e.g., certain shippers on Seaway), customers are required to ship a minimum volume over an agreed-upon period, with make-up rights. Revenue attributable to shipper make-up rights is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired (typically a one year contractual period), or when the pipeline is otherwise released from its transportation service performance obligation.

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The following table presents selected information regarding our onshore crude oil pipelines at February 1, 2015:

| Description of Asset | Location(s) | Our Ownership Interest | Pipeline Length (Miles) |
|---|---|---|---|
| Crude oil pipelines: | | | |
| Seaway Pipeline (1) | Texas, Oklahoma | 50.0% (2) | 1,300 |
| Red River System (1) | Texas, Oklahoma | 100.0% | 1,602 |
| West Texas System (1) | Texas, New Mexico | 100.0% | 899 |
| South Texas Crude Oil Pipeline System (1) | Texas | 100.0% | 860 |
| Basin Pipeline (1) | Texas, New Mexico, Oklahoma | 13.0% (3) | 519 |
| Eagle Ford Crude Oil Pipeline System | Texas | 50.0% (4) | 175 |
| Total | | | 5,355 |

(1) 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) We proportionately consolidate our undivided interest in the Basin Pipeline.
(4) Our ownership interest in the Eagle Ford Crude Oil Pipeline System is held indirectly through our equity method investment in Eagle Ford Pipeline LLC.

The maximum number of barrels per day that our onshore crude oil pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and grades of crude oil being transported). As a result, we measure the utilization rates of our crude oil pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 1,278 MBPD, 1,175 MBPD and 828 MBPD during the years ended December 31, 2014, 2013 and 2012, respectively.

As noted previously, certain of our crude oil pipelines are subject to regulation. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information.

The following information describes each of our principal onshore crude oil pipelines, all of which we operate with the exception of the Basin Pipeline and Eagle Ford Crude Oil Pipeline System.

§ The Seaway Pipeline connects the Cushing, Oklahoma crude oil hub with markets in Southeast Texas. The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System. The Cushing hub is a major industry trading hub and price settlement point for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange.

The Longhaul System consists of two 500-mile, 30-inch diameter pipelines that provide north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal located near Freeport, Texas and our terminal located near Katy, Texas. We completed the second of these two pipelines (referred to as the "Seaway Loop") in July 2014. With the looping project complete, the aggregate transportation capacity of the Longhaul System is approximately 850 MBPD, depending on the type and mix of crude oil being transported and other variables. Crude oil deliveries using the Seaway Loop commenced in December 2014.

The Freeport System consists of a marine dock, three pipelines and other related facilities that transport crude oil to and from Freeport, Texas to the Jones Creek terminal. The Texas City System consists of a marine 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 provide intrastate transportation service. The intrastate transportation capacity of the Freeport System and Texas City System is approximately 220 MBPD and 800 MBPD, respectively.

In total, the Seaway Pipeline includes 7.9 MMBbls of crude oil storage tank capacity (3.9 MMBbls net to our ownership interest). This includes two storage tanks at the Jones Creek terminal that are connected to the Longhaul System and two storage tanks owned by Seaway that are located at our Enterprise Crude Houston ("ECHO") terminal.

In January 2013, Seaway made certain pump station additions and modifications at its Cushing origin. In January 2014, Seaway placed into service a 65-mile, 36-inch diameter pipeline from its Jones Creek terminal to our ECHO terminal. In August 2014, Seaway completed construction of an additional 100-mile, 30-inch diameter pipeline between ECHO and refinery customers in the Beaumont/Port Arthur, Texas area. In January 2015, Seaway placed into service the aforementioned two storage tanks at our ECHO terminal.

The interstate tariffs charged by Seaway to its committed and uncommitted shippers are the subject of an ongoing rate proceeding at the FERC. For information regarding this proceeding, see "Regulatory Matters – FERC Regulation – Liquids Pipelines," within this Part I, Item 1 and 2 discussion.

§ The Red River System transports crude oil from North Texas and southern Oklahoma for delivery to local refineries and pipeline interconnects for further transportation to the Cushing hub. The Red River System is connected to 1.2 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 0.5 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 growing production from the Eagle Ford Shale supply basin, to refineries in the Greater Houston area.

The South Texas Crude Oil Pipeline System includes our Eagle Ford Expansion pipeline, which has a crude oil transportation capacity of 350 MBPD. The Eagle Ford Expansion pipeline originates at our Lyssy station in Wilson County, Texas and extends 147 miles to Sealy, Texas. It includes 2.4 MMBbls of crude oil storage consisting of 0.2 MMBbls in Karnes County, Texas, 0.6 MMBbls in Wilson County, Texas, 0.4 MMBbls in Gonzales County, Texas and 1.2 MMBbls at Sealy. Crude oil supplies arriving at Sealy on the Eagle Ford Expansion pipeline are delivered to refiners in the Greater Houston area using affiliate and third party owned pipelines. In addition, shippers have access to our ECHO crude oil storage terminal.

Including the storage capacity associated with the Eagle Ford Expansion pipeline, the South Texas Crude Oil Pipeline System includes a total of 3.4 MMBbls of crude oil storage capacity that we own and operate.

The South Texas Crude Oil Pipeline System includes our Rancho I and II pipelines. The Rancho I pipeline extends 63 miles from Sealy, Texas to our ECHO terminal. We are currently constructing a loop pipeline (the "Rancho II" pipeline) that will consist of 88-miles of 36-inch diameter pipe extending from Sealy to ECHO. We expect the Rancho II pipeline to be completed in July 2015.

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

§ The Eagle Ford Crude Oil Pipeline System transports crude oil and condensate for producers in South Texas. This system consists of a 140-mile crude oil and condensate pipeline extending from Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and continuing on to Corpus Christi, Texas. The system also includes a 35-mile pipeline segment extending from Three Rivers to an interconnect with our South Texas Crude Oil Pipeline System in Wilson County. The Eagle Ford Crude Oil Pipeline System, which commenced operations in

July 2013, currently has a transportation capacity of 300 MBPD and includes a marine barge terminal facility at Corpus Christi and 1.8 MMBbls of storage capacity across the system (0.9 MMBbls net to our ownership interest). Plains All American Pipeline, L.P. ("Plains"), our joint venture partner in the pipeline, serves as operator of the system.

In September 2013, we, along with Plains, announced an expansion of the Eagle Ford Crude Oil Pipeline System. This expansion project is expected to increase the pipeline system's capacity to transport light and

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medium grades of crude oil from 300 MBPD to 470 MBPD in order to accommodate expected volumes from Plains' Cactus pipeline. In addition, the joint venture will construct an additional 2.3 MMBbls of storage capacity at Gardendale, Tilden and Corpus Christi, Texas. In November 2014, we, along with Plains, announced a second major expansion project involving the Eagle Ford Crude Oil Pipeline System. This expansion project entails the construction of a new 55-mile crude oil gathering system that will connect Karnes County and Live Oak County production areas in Texas to the joint venture's Three Rivers terminal. The joint venture will also construct an additional 70-mile, 20-inch pipeline from Three Rivers to Corpus Christi as well as expand storage and pumping capacity at Three Rivers. When combined with the expansion project announced in September 2013, this project effectively loops the Eagle Ford Crude Oil Pipeline System from Gardendale to Corpus Christi and increases the system's capacity to transport light and medium grades of crude oil to over 600 MBPD. Both expansion projects are supported by long-term production commitments and are expected to be placed into service in the third quarter of 2015.

In November 2014, the joint venture also announced plans to construct a new deep water marine terminal on the Corpus Christi ship channel to support the expected increase in crude oil volumes to be shipped via pipeline to the region. The dock is being designed to handle a variety of ocean-going vessels and is expected to be in service by 2017.

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

Historically, southeast Texas refineries have been supplied primarily by waterborne imports of crude oil. With the increase in North American production, crude oil from the Eagle Ford, Permian, Mid-Continent, Bakken and Canada is flowing into Southeast Texas and displacing waterborne crude oil imports. Due to growing domestic production, we expect a significant increase in North American crude oil deliveries to the Gulf Coast market, which currently lacks sufficient storage capacity and has an inadequate distribution system for handling these varying grades of domestic crude oil. In response, we are in the process of expanding our Oiltanking Houston and ECHO crude oil terminals (as described below). Upon completion of these expansion projects, we will be able to provide Gulf Coast refiners with an integrated system featuring supply diversification, significant storage capabilities and a high capacity pipeline distribution system that will be directly connected to customers having an aggregate refining capacity of approximately 3.9 MMBPD.

The following table presents selected information regarding our crude oil terminals at February 13, 2015:

| Description of Asset | Location(s) | Our Ownership Interest | Storage Capacity (MMBbls) |
|---|---|---|---|
| Crude oil terminals: | | | |
| Houston Ship Channel terminal | Texas | 100.0% | 20.1 |
| ECHO terminal | Texas | Various (1) | 3.0 |
| Cushing terminal | Oklahoma | 100.0% | 3.3 |
| Midland terminal | Texas | 100.0% | 1.4 |
| Morgan's Point terminal | Texas | 100.0% | 0.3 |
| Total | | | 28.1 |

(1) We own 100% of six tanks at our ECHO terminal having a combined capacity of 2.0 MMBbls. Seaway owns two tanks at our ECHO terminal having a combined capacity of 1.0 MMBbls, of which we have an indirect 50% ownership interest through our equity method investment in Seaway.

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

§ The Houston Ship Channel terminal complex, which consists of Oiltanking's Jacintoport and Appelt terminals, is one of the largest such facilities on the Gulf Coast and provides terminaling services to major

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integrated oil companies, marketers, distributors and chemical companies. We acquired a controlling financial interest in Oiltanking on October 1, 2014 and completed the Oiltanking Merger on February 13, 2015. We now own 100% of the Houston Ship Channel terminal complex.

Our storage and distribution network is highly integrated with the greater Houston petrochemical and refining complex. As of December 31, 2014, crude oil and condensates accounted for approximately 82% of the terminal's active storage capacity, with refined products and specialty chemicals accounting for the remaining capacity. Substantially all of the terminal's current storage capacity of 20.1 MMBbls was under firm contract at December 31, 2014.

Our Houston Ship Channel terminal complex has extensive waterfront access, consisting of six deep-water ship docks and two barge docks. We can accommodate vessels with up to a 45 foot draft, including Suezmax tankers, which are the largest tankers that can navigate the Houston Ship Channel. We believe that our location on the Houston Ship Channel to the east of the Beltway 8 Bridge enables us to handle larger vessels than our competitors who are located to the west of the Beltway 8 Bridge because our waterfront has fewer draft and beam restrictions.

The size and structure of our waterfront at the Houston facility allows us not only to receive and unload products for our storage customers, but also to provide third party docking services for which we receive throughput fees. Our LPG export and NGL import terminals, both of which are a component of our NGL Pipelines & Services business segment, are located at the Houston Ship Channel terminal complex.

We believe our Houston Ship Channel terminal complex is well positioned to take advantage of changing crude oil logistics along the Gulf Coast as a result of announced third party pipeline construction projects and waterborne and rail movements. In response, a number of expansion projects are underway at the Houston Ship Channel terminal complex. Since 2012, Oiltanking has announced expansion projects at our Appelt terminal totaling approximately 10.0 MMBbls of crude oil storage capacity, of which approximately 6.9 MMBbls has been placed into service as of December 31, 2014. We expect to place the remaining 3.1 MMBbls of crude oil storage capacity into service in the fourth quarter of 2015 and in the first quarter of 2016.

In addition to the Appelt projects, we are expanding the pipeline infrastructure associated with our Houston Ship Channel terminal to include connectivity with Crossroads Junction, which is the termination point of the Houston lateral of TransCanada Corporation's Gulf Coast Pipeline and the origination point of Shell Pipeline's Houston-to-Houma, or Ho-Ho, Pipeline. We completed a new 24-inch pipeline in late 2014 that provides our terminal customers direct access to the origination point of the Ho-Ho Pipeline, which transports crude oil from the Houston area eastbound to refining centers in Texas and Louisiana. We are constructing a 36-inch pipeline that will give our terminal customers access to the termination point of the Gulf Coast Pipeline, which is expected to connect to the Keystone XL pipeline if approved and constructed. We expect that the 36-inch pipeline will be completed by mid-2015.

§ The ECHO, or Enterprise Crude Houston, storage terminal is located in Houston, Texas and provides storage customers with access to major refineries located in the Houston and Texas City area. 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 operationally support the expansion of our South Texas Crude Oil Pipeline System and Seaway Pipeline. Currently, we have 3.0 MMBbls of crude oil storage capacity at the ECHO terminal. This includes 1.1 MMBbls of storage capacity that we placed into service during 2014 and an additional 1.0 MMBbls (or 0.5 MMBbls net to our interest) that Seaway constructed, owns and placed into service at our ECHO terminal in January 2015.

In May 2013, we announced an expansion project at ECHO that would entail the construction of additional storage capacity. Also, we plan to construct 55 miles of associated pipelines to directly connect the ECHO storage facility with several major refineries in the Southeast Texas market. These expansion projects are expected to be completed in phases with final completion expected in the second quarter of 2015. At that time, we expect our ECHO terminal to have an aggregate crude oil storage capacity of 7.4 MMBbls.

§ The Cushing terminal provides crude oil storage, pumpover and trade documentation services. Our terminal in Cushing, Oklahoma has an aggregate storage capacity of 3.3 MMBbls through the use of 20 above-ground storage tanks.

§ The Midland terminal provides crude oil storage, pumpover and trade documentation services. The Midland, Texas terminal has an aggregate storage capacity of 1.4 MMBbls through the use of 14 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 factors such as delivery location or crude oil quality. We also use derivative instruments to mitigate our exposure to commodity price risks associated with our crude oil marketing activities.

U.S. federal law has prohibited the export of crude oil since the 1970s, except for crude oil sent to Canada. While untreated crude oil cannot be exported, refined products such as gasoline can be exported. Due to increasing U.S. crude oil production, producers have been lobbying the U.S. government to lift the ban on crude oil exports. Producers believe that fully lifting the ban will support domestic production efforts. In March 2014, the U.S. Department of Commerce ("Commerce Department") allowed us to begin exporting processed condensate, which is a type of ultralight crude oil that has been processed through a distillation facility. In December 2014, the Commerce Department granted permission for additional companies to begin exporting condensate. Our first condensate cargo was loaded in July 2014. In total, we loaded 3.7 MMBbls of condensate for export in 2014. We continue to monitor developments in this new business area.

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 Houston Ship Channel and ECHO terminals) 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, storage 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 crude oil business can be characterized by strong competition for crude oil volumes. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and 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 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms.

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, 2015:

| 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% | | 107 | 600 |
| High Island Offshore System | 100.0% | | 287 | 500 |
| Falcon Natural Gas Pipeline | 100.0% | | 14 | 400 |
| Anaconda Gathering System | 100.0% | | 183 | 300 |
| Green Canyon Laterals | Various | (2) | 34 | 213 |
| Manta Ray Offshore Gathering System | 25.7% | (3) | 237 | 205 |
| Nautilus System | 25.7% | (3) | 101 | 154 |
| VESCO Gathering System | 13.1% | (4) | 125 | 65 |
| Total | | | 1,223 | |

(1) Amounts presented are net to our ownership interest in the associated asset.
(2) We proportionately consolidate our undivided interests, which range from 2.7% to 33.3%, in 28 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 VESCO Gathering System is held indirectly through our equity method investment in VESCO. We account for our investment in VESCO under the NGL Pipelines & Services business segment.

On a weighted-average basis, overall utilization rates for our offshore natural gas pipelines were approximately 16.3%, 17.7% and 21.7% during the years ended December 31, 2014, 2013 and 2012, 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 pipeline transports natural gas from our Independence Hub platform and a pipeline interconnect downstream of our Independence Hub platform 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 interconnects with 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, which 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.

§ 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.

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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 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. This system includes two pipeline junction platforms.

§ 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 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, 2015:

| Description of Asset | Our Ownership Interest | | Length (Miles) | Approximate Net Capacity (MBPD) (1) |
|---|---|---|---|---|
| Offshore crude oil pipelines: | | | | |
| Shenzi Oil Pipeline | 100.0% | | 83 | 230 |
| Poseidon Oil Pipeline System | 36.0% | (2) | 366 | 155 |
| Cameron Highway Oil Pipeline | 50.0% | (3) | 374 | 150 |
| Allegheny Oil Pipeline | 100.0% | | 40 | 140 |
| Marco Polo Oil Pipeline | 100.0% | | 37 | 120 |
| Constitution Oil Pipeline | 100.0% | | 67 | 80 |
| SEKCO Oil Pipeline | 50.0% | (4) | 145 | 58 |
| Tarantula | 100.0% | | 4 | 30 |
| Total | | | 1,116 | |

(1) Amounts presented are net to our ownership interest in the associated asset.
(2) 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").
(3) 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").
(4) Our ownership interest in the SEKCO Oil Pipeline is held indirectly through our equity method investment in Southeast Keathley Canyon Pipeline Company, L.L.C. ("SEKCO").

On a weighted-average basis, overall utilization rates for our offshore crude oil pipelines were approximately 35.9%, 31.3% and 30.6% during the years ended December 31, 2014, 2013 and 2012, respectively.

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

§ 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.

§ 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 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.

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§ 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.

§ The SEKCO Oil Pipeline connects the third party-owned Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island 205, which is part of our Poseidon Oil Pipeline System. The SEKCO Oil Pipeline was completed and started earning firm capacity reservation fees in July 2014. Crude oil shipments commenced in January 2015 when the Lucius oil and gas field started operations.

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 commodity charges and/or demand-type fees billable to customers. 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. Demand-type 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. Contracts for platform services often include both demand-type fees and commodity charges, but demand-type 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, 2015:

| 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 investees, 15 pipeline junction and service platforms (12 of which we operate). Unlike hub platforms, pipeline junction and service platforms do not have processing capacity.

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With respect to natural gas processing capacity, the overall utilization rates (on a weighted-average basis) of our offshore hub platforms were approximately 8.1%, 11.2% and 16.2% during the years ended December 31, 2014, 2013 and 2012, respectively. With respect to crude oil processing capacity, the overall utilization rates (on a weighted-average basis) of our offshore platforms were approximately 16.9%, 17.5% and 18.9% during the years ended December 31, 2014, 2013 and 2012, 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.

§ 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 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, including approximately 680 miles of pipelines; (ii) a butane isomerization complex, associated deisobutanizer units and related pipeline assets; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines aggregating approximately 4,200 miles, terminals and related marketing activities; and (v) marine transportation.

Propylene fractionation and related operations. Our propylene fractionation and related operations consist of seven propylene fractionation plants, including pipeline systems aggregating approximately 680 miles in length, and related petrochemical marketing activities. This business includes an export facility and associated above-ground storage spheres for polymer grade propylene located in Seabrook, Texas. We operate all of our propylene fractionation and related assets except for the Lake Charles Pipeline in Louisiana.

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



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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, all of which are the primary costs of propylene fractionation activities. 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 provisions whereby the customer pays us a fee if certain volume thresholds are not met over a contractual term.

In our petrochemical marketing activities, we purchase refinery grade propylene on the open market for fractionation at our facilities and sell the resulting products at market-based prices. The selling price of these products may include pricing differentials for factors such 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. In order 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, 2015:

| 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) | 81 | 95 |
| BRPC (one unit) | Louisiana | 30.0% | (2) | 7 | 23 |
| Total | | | | 88 | 118 |

(1) We proportionately consolidate a 66.7% undivided interest in three of the propylene fractionation units, which have an aggregate 41 MBPD of total plant capacity. The remaining three propylene fractionation units 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. On a weighted-average basis, overall utilization rates of our propylene fractionation facilities were approximately 84.7%, 87.4% and 87.8% during the years ended December 31, 2014, 2013 and 2012, respectively.

This business includes a marine export facility located on the Houston Ship Channel at Seabrook, Texas that can load vessels at rates up to 5,000 barrels per hour. This export facility also includes above-ground storage spheres for polymer grade propylene. A renovation of this facility is expected to be completed in the second quarter of 2015.

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The following table presents selected information regarding our petrochemical pipelines at February 1, 2015:

| Description of Asset | Location(s) | Ownership Interest | | Length (Miles) |
|---|---|---|---|---|
| Petrochemical pipelines: | | | | |
| Lou-Tex and Sabine Propylene | Texas, Louisiana | 100.0% | | 278 |
| Texas City RGP Gathering System | Texas | 100.0% | | 171 |
| North Dean Pipeline System | Texas | 100.0% | | 149 |
| Propylene Splitter PGP Distribution System | Texas | 100.0% | | 34 |
| Lake Charles PGP Pipeline | Louisiana | 50.0% | (1) | 26 |
| La Porte PGP Pipeline | Texas | 50.0% | (2) | 20 |
| Total | | | | 678 |

(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 delivery point 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 per day that our petrochemical pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our petrochemical pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes were 124 MBPD, 118 MBPD and 117 MBPD during the years ended December 31, 2014, 2013 and 2012, respectively.

In June 2012, we announced plans to build a propane dehydrogenation ("PDH") facility, with capacity to produce up to 1.65 billion pounds per year (or approximately 750 thousand metric tons per year or 25 MBPD) of polymer grade propylene. The PDH facility is expected to consume approximately 35 MBPD of propane as feedstock and be located adjacent to our Mont Belvieu complex. 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 fourth quarter of 2016.

Butane isomerization and deisobutanizer operations. Our Mont Belvieu complex includes three isomerization units and nine deisobutanizer ("DIB") units. Each of our isomerization units includes two reactors that convert normal butane feedstock into mixed butane, which is a stream of isobutane and normal butane. DIBs then separate the isobutane from the normal butane through fractionation. Any remaining unconverted (or residual) normal butane generated by the DIB process is then recirculated through the isomerization process until it has been converted into varying grades of isobutane, including high-purity isobutane. The isomerization process also produces natural gasoline as a by-product. We also use our DIB units to fractionate mixed butane produced from our NGL fractionators and other sources into isobutane and normal butane. Our butane isomerization assets comprise the largest commercial isomerization facility in the U.S. These operations include a 70-mile pipeline system used to transport high-purity isobutane from Mont Belvieu, Texas to Port Neches, Texas. We own and operate our butane isomerization facility and related pipeline assets.

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. The processing capacity of our isomerization facility is 116 MBPD. On

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a weighted-average basis, utilization rates for this facility were approximately 80.2%, 81.0% and 81.9% during the years ended December 31, 2014, 2013 and 2012, respectively.

We use certain DIB units to fractionate mixed butanes produced from our NGL fractionation activities, from imports and from other sources into isobutane and normal butane. The operating flexibility provided by our multiple standalone DIBs enables us to take advantage of fluctuations in demand and prices for different types of butane. We measure the utilization of our standalone DIB units in terms of processing volumes, which averaged 82 MBPD, 67 MBPD and 46 MBPD for the years ended December 31, 2014, 2013 and 2012, respectively. Standalone DIB processing volumes have increased as a result of increased NGL fractionation volumes at our Mont Belvieu complex.

The results of operation of this business are generally dependent on the volume of normal and mixed butanes processed, the level of toll processing fees charged to customers and prices received for by-products. 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, all of which are the primary costs of isomerization. These assets provide 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 underlying processes.

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.

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 commodity derivative instruments. To the extent that we produce MTBE, it is sold exclusively 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 51.6%, 90.3% and 71% during the years ended December 31, 2014, 2013 and 2012, respectively. Our octane enhancement facility operated at lower utilization rates in 2014 primarily due to mechanical restrictions. These restrictions are expected to be remedied during the facility's annual turnaround in the first quarter of 2015.

We also own a facility located on the Houston Ship Channel that produces up to 4 MBPD of high purity isobutylene ("HPIB") and includes an associated storage facility with 0.6 MMBbls of storage capacity, 0.2 MMBbls of which is pressurized storage. 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. In general, we sell HPIB at market-based prices with a cost-based floor. On a weighted-average basis, utilization rates for this facility were 47.2%, 40.6% and 39.5% for the years ended December 31, 2014, 2013 and 2012, respectively.

Refined products pipelines. Refined products pipelines include our TE Products Pipeline and an investment in Centennial Pipeline LLC ("Centennial"). The refined petroleum products (or "refined products") transported by these pipelines are produced by refineries and primarily include motor gasoline. The results of operations for these 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.

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The following table presents selected information regarding our refined products pipelines and related terminal and storage assets at February 1, 2015:

| 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% | 3,403 | 18.2 |
| Centennial Pipeline (2) | Texas to Illinois | 50.0% (3) | 795 | 1.2 |
| Total | | | 4,198 | 19.4 |

(1) In addition to the 18.2 MMBbls of refined products storage capacity presented in the table, we have 3.7 MMBbls of storage capacity that is used to support NGL operations on our TE Products Pipeline. Our NGL storage and terminal assets are accounted for under the 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.

The maximum number of barrels per day that our refined products pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our refined products 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, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Refined products transportation (MBPD) | 412 | 373 | 383 |
| Petrochemical transportation (MBPD) | 137 | 120 | 101 |
| NGL transportation (MBPD) | 65 | 72 | 66 |

Due to increased refinery production in the Midwest and Northeast U.S. and lower overall demand for refined products in these regions, demand for refined products produced along the Gulf Coast has decreased. In response, we repurposed significant components of our TE Products Pipeline for use by the ATEX pipeline to accommodate the southbound delivery of ethane produced from the Marcellus and Utica Shale formations.

As noted previously, these pipelines are subject to regulation. See "Regulatory Matters" within this Part I, Item 1 and 2 discussion for additional information regarding governmental oversight of liquids pipelines, including tariffs charged for transportation services.

The following information describes each of our principal refined products pipelines. We operate the TE Products Pipeline system and our joint venture partner in Centennial operates the Centennial Pipeline.

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The TE Products Pipeline is a 3,403-mile pipeline system comprised of 3,085 miles of interstate pipelines and 318 miles of intrastate Texas pipelines. Refined products and certain NGLs are transported from the upper Texas Gulf Coast to Seymour, Indiana. From Seymour, segments of the TE Products Pipeline extend to Chicago, Illinois; Lima, Ohio; Selkirk, New York; and near Philadelphia, Pennsylvania. East of Seymour, Indiana, the TE Products Pipeline is primarily dedicated to NGL transportation service.

Products are delivered to various locations along the system, including terminals owned either by us or third parties and to various connecting pipelines. We own and operate five refined products truck terminals and various storage facilities located along the TE Products Pipeline.

In January 2014, our ATEX pipeline commenced operations. In addition to new construction, this project involved repurposing components of the TE Products Pipeline to accommodate southbound delivery of ethane to the U.S. Gulf Coast. The repurposed pipeline assets were reclassified to the NGL Pipelines & Services business segment (on a prospective basis in January 2014) when ATEX commenced operations.

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TE Products Pipeline assets that were not repurposed remain in the Petrochemical & Refined Products Services business segment.

§ The Centennial Pipeline is a refined products pipeline that extends from an origination facility located on our TE Products Pipeline in Beaumont, Texas, to Bourbon, Illinois. The Centennial Pipeline includes a refined products storage terminal located near Creal Springs, Illinois with a gross storage capacity of 2.3 MMBbls (or 1.2 MMBbls net to our ownership interest).

Refined products terminals. We own a refined products storage terminal and export facility located in Beaumont, Texas and refined products marketing and distribution terminals located in Alabama and Mississippi. The results of operations from our refined products terminaling services are primarily dependent upon the level of volumes a customer stores at each terminal and the 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 regardless of the volume the customer actually stores at the terminal. The results of operations from our refined products export facility are primarily dependent upon the volume handled and the associated fees we charge for loading services. Revenue is recorded in the period the export services are provided. Customers are typically billed a fee per unit of volume loaded. With respect to our export terminal operations, revenue may also include deficiency fees charged to customers that reserve capacity at our export facility and later fail to use such capacity. Deficiency fee revenue is recognized when the customer fails to utilize the specified export capacity as required by contract.

The following information describes our Beaumont refined products storage terminal and export facility, which are the principal assets classified in this business. We operate both assets.

§ The Beaumont West Terminal complex, which consists of Oiltanking's Beaumont operations, has 5.5 MMBbls of storage capacity and serves as a regional strategic and trading hub for refined petroleum products. We acquired a controlling financial interest in Oiltanking on October 1, 2014 and completed the Oiltanking Merger on February 13, 2015. We now own 100% of the Beaumont West Terminal.

Located on the Neches River near Beaumont, Texas, our Beaumont West Terminal is integrated with the Beaumont/Port Arthur petrochemical and refining complex, and provides customers with additional services, such as mixing, blending, heating and marine vapor recovery. As of December 31, 2014, refined products accounted for approximately 88% of the terminal's active storage capacity, with specialty chemicals accounting for the remaining capacity. Substantially all of the terminal's current storage capacity of 5.5 MMBbls was under firm contract at December 31, 2014.

Waterfront capabilities at our Beaumont West Terminal currently consist of two deep-water ship docks that can accommodate vessels with drafts of up to 40 feet, and two barge docks that can accommodate vessels with drafts of up to 12 feet.

Our Beaumont facility handles products through a number of transportation modes, including third party pipelines interconnected to local refineries and production facilities, our dedicated pipeline system to a customer's chemical production facility located in Port Neches, Texas, and third party ships and barges arriving at our deep-water docks.

In June 2014, Oiltanking announced the approval of a project at this terminal to construct new storage tanks, pipelines and dock infrastructure to serve crude oil customers. This multi-phase project is expected to have a total capacity of up to 6.2 MMBbls of crude oil storage when all currently planned phases have been completed. The first phase includes pipeline connections and manifold infrastructure and the construction of a new finger pier with two new deep-water docks. The new docks will be configured to load and unload crude oil and related products at rates sufficient to accommodate expected growth at the terminal. We anticipate that the first storage tanks will be placed into service by the third quarter of 2015. When completed, we expect to classify the crude oil assets within our Onshore Crude Oil Pipelines & Services business segment.

- Our Beaumont Refined Products Export Terminal, located on the Neches River, can load cargoes at rates up to 15,000 barrels per hour. The facility includes a dock with a 40-foot draft that can accommodate Panamax size vessels that have a capacity of up to 400,000 barrels. The terminal receives products from eight refineries, representing approximately 3.3 MMBPD of capacity, as well as our TE Products Pipeline and the third party-owned Colonial Pipeline. This terminal has access to more than 12.0 MMBbls of refined products storage including capacity at our Beaumont West Terminal (see above) and 3.0 MMBbls of storage capacity located along our TE Products Pipeline in Beaumont, Texas.

In May 2014, we began loading cargoes of refined products for export at the terminal, which was previously inactive, with the dock operating on a reservation basis. The facility was fully subscribed within the first six months of operations. We are also expanding the terminal with additional on-site storage and ancillary equipment for gasoline blending operations. Reactivation of the terminal, as well as its expansion, was supported by long-term customer commitments. With its strategic location and enhanced capabilities, the Beaumont Refined Products Export Terminal provides optionality for exporters, allowing them to capture added value from the evolving fundamentals of the domestic and international refined products markets while avoiding the long wait times associated with Houston Ship Channel refined products export facilities.

Refined products marketing activities. 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 factors such as delivery location. We use derivative instruments to mitigate our exposure to commodity price risks associated with our refined products marketing activities.

Marine transportation. 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 located 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 either 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, U.S. Department of Commerce and the U.S. Coast Guard ("USCG") and federal and state laws. For additional information regarding these regulations, see "Regulatory Matters – Federal Regulation of Marine Operations," within this Part I, Item 1 and 2 discussion.

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The following table presents selected information regarding our marine transportation assets at February 1, 2015:

| Class of Equipment | Number in Class | Capacity/ Horsepower (as indicated by sign) (1) |
|---|---|---|
| Inland marine transportation assets: | | |
| Barges | 9 | < 25,000 bbls |
| Barges | 115 | > 25,000 bbls |
| Tow boats | 18 | < 2,000 hp |
| Tow boats | 40 | ≥ 2,000 hp |
| Offshore marine transportation assets: | | |
| Ocean-certified tank barges | 7 | ≥ 20,000 bbls |
| Tow boats | 5 | ≥ 2,000 hp |

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

Our fleet of marine vessels operated at an average utilization rate of 93.1%, 93.9% and 90.9% during the years ended December 31, 2014, 2013 and 2012, 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 of 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 purposes) and normal butane (for blending in motor gasoline).

Our marine transportation business exhibits some seasonal variation. Demand for motor gasoline is generally stronger in the spring and summer months due to the summer driving season. Weather events, such as hurricanes and tropical storms in the Gulf of Mexico, can adversely impact both the offshore and inland marine transportation business. Also, cold weather and ice during the winter months can negatively impact our inland marine 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 supporting pipeline and storage infrastructure. We compete with other octane additive manufacturing companies primarily on the basis of price.

With respect to our TE Products Pipeline, its 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 markets served by our TE Products Pipeline and river terminals. The TE Products

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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 material challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to 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.

Regulatory Matters

The following information describes the principal effects of regulation on our business activities, including those regulations involving safety and environmental matters and the rates we charge customers for transportation services.

Safety Matters

The safe operation of our pipelines and other assets is a top priority of our partnership. We are committed to protecting the environment and the health and safety of the public and those working on our behalf by conducting our business activities in a safe and environmentally responsible manner.

Occupational Safety and Health. Certain of our facilities are subject to the general industry requirements of the Federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes. We believe we are in material compliance with OSHA and the similar state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures of employees.

Certain of our facilities are subject to OSHA Process Safety Management ("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 involving a chemical at or above a specified threshold (as defined in the regulations) or any process which involves certain flammable gases or liquids. In addition, we are subject to the Risk Management Plan regulations of the U.S. Environmental Protection Agency ("EPA") at certain facilities. These regulations are intended to complement the OSHA PSM regulations. These EPA regulations require us to develop and implement a risk management program that includes a five-year accident history report, an offsite consequence analysis process, a prevention program and an emergency response program. We believe we are operating in material compliance with the OSHA PSM regulations and the EPA's Risk Management Plan requirements.

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 the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") require us to report spills and releases of hazardous chemicals in certain situations.

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Pipeline Safety. We are subject to extensive regulation by the U.S. DOT authorized under various provisions of Title 49 of the United States Code and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. These statutes require companies that own or operate pipelines to (i) comply with such regulations, (ii) permit access to and copying of pertinent records, (iii) file certain reports and (iv) provide information as required by the U.S. Secretary of Transportation. We believe we are in material compliance with these DOT regulations.

We are subject to DOT pipeline integrity management regulations that 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 include populated areas, unusually sensitive areas and commercially navigable waterways. The regulation requires the development and implementation of an integrity management program that utilizes internal pipeline inspection techniques, pressure testing or other equally effective means to assess the integrity of pipeline segments in HCAs. These regulations also require 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 in the assessment and analysis process. We have identified our pipeline segments in HCAs and developed an appropriate integrity management program for such assets.

In January 2012, President Obama signed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "2011 Pipeline Safety Act"). This act provides for additional regulatory 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 provides for (i) additional pipeline damage prevention measures, (ii) allowing the Secretary of Transportation to require automatic and remote-controlled shut-off valves on new pipelines, (iii) requiring the Secretary of Transportation 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.

In total, our pipeline integrity costs for the years ended December 31, 2014, 2013 and 2012 were $99.0 million, $128.0 million and $150.0 million, respectively. Of these annual totals, we charged $59.7 million, $70.4 million and $70.6 million to operating costs and expenses during the years ended December 31, 2014, 2013 and 2012, respectively. The remaining annual pipeline integrity costs were capitalized and treated as sustaining capital projects. We expect the cost of our pipeline integrity program, regardless of whether such costs are capitalized or expensed, to approximate $128.0 million for 2015.

DOT regulations have incorporated by reference, the American Petroleum Institute Standard 653 ("API 653") as the industry standard for the inspection, repair, alteration and reconstruction of storage tanks. API 653 requires regularly scheduled inspection and repair of such tanks. These periodic tank maintenance requirements may result in 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.

In January 2015, the White House announced plans to regulate methane emissions attributable to the upstream oil and gas industry, including activities related to gathering and compression, as a greenhouse gas. See "Climate Change Debate" within this Regulatory Matters section. This announcement indicated that the DOT through its Pipeline and Hazardous Materials Safety Administration, or PHMSA, will be issuing new natural gas regulations with the intent to improve safety as well as to reduce methane emissions. Until such proposed rules are developed and published, the impact on our operations is not known.

Environmental Matters

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: CERCLA; the Resource Conservation and Recovery Act ("RCRA"); the Federal Clean Air Act ("CAA"); the Clean Water Act ("CWA"); the Oil Pollution Act of 1990 ("OPA"); 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. However, environmental and safety laws and regulations are subject to change. The trend in environmental regulation has been to place more restrictions and limitations on activities that may be perceived to impact the environment, and thus there can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. New or revised regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our financial position, results of operations and cash flows.

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

Air Quality. Our operations are associated with regulatory permitted emissions of air pollutants. As a result, we are subject to the CAA and comparable state laws and regulations including state air quality 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.

Water Quality. The CWA and comparable state laws impose strict controls on the discharge of crude oil and its derivatives into regulated waters. The CWA provides penalties for any discharge 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 crude oil spill liability is the OPA, which addresses three principal areas of crude 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 crude oil above certain thresholds, onshore facilities are required to file oil spill response plans with the USCG, the DOT's 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 crude oil is discharged may be liable for remediation costs, including damage to surrounding natural resources. Any unpermitted release of petroleum or other pollutants from our pipelines or facilities could result in fines or penalties as well as significant remediation costs.

Contamination resulting from spills or releases of petroleum products is an inherent risk within the 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 impact will not be material in the aggregate.

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 future pipeline construction projects could be adversely impacted.

Disposal of Hazardous and Non-Hazardous Wastes. 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 solid waste. We also utilize waste minimization and recycling processes to reduce the volumes of our solid wastes.

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 parties. 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.

Endangered Species. The federal Endangered Species Act, as amended, and comparable state laws, may restrict commercial or other 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.

FERC Regulation

Liquids Pipelines. Certain of our natural gas liquids, petroleum products and crude oil pipeline systems are interstate common carriers subject to regulation by the FERC under the Interstate Commerce Act ("ICA"). These pipelines (referred to as "interstate liquids pipelines") include, but are not limited to, the following principal assets: ATEX, Dixie System, TE Products Pipeline, Front Range Pipeline, Mid-America Pipeline System, Seaway Pipeline, Seminole Pipeline and Texas Express Pipeline.

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The ICA prescribes that the interstate rates we charge for transportation on these interstate liquids pipelines must be just and reasonable, and that the rules applied to our services not unduly discriminate against or confer any undue preference upon any shipper. FERC regulations implementing the ICA further require that interstate liquids pipeline transportation rates and rules 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. Upon completion of such an investigation, the FERC may require refunds of amounts collected above what it finds to be a just and reasonable level, together with interest. 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 (including interest) for damages sustained for a period of up to two years prior to the filing of its complaint.

The rates charged for our interstate liquids pipeline services are generally based on 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 U.S. 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, 2011 and ending June 30, 2016, we have been permitted by the FERC to adjust these indexed rate ceilings annually by the PPI plus 2.65%. The FERC is expected to issue an order in 2015 establishing the index for the five-year period commencing July 1, 2016. As an alternative to this indexing methodology, we may also choose to support changes in our rates based on a cost-of-service methodology, by obtaining advance approval to charge "market-based rates," or by charging "settlement rates" agreed to by all affected shippers.

In June 2013, certain parties filed a complaint at the FERC against Enterprise TE Products Pipeline Company LLC ("Enterprise TE") alleging that Enterprise TE's cancellation of certain distillate and jet fuel transportation services violated a provision of a settlement agreement and requested reinstatement of the transportation services and damages. In October 2013, the FERC issued an order holding that Enterprise TE violated the provision in the settlement agreement. While the FERC found that it did not have authority to require Enterprise TE to reinstate the cancelled services, it set the case for an evidentiary hearing to determine if any monetary damages were appropriate. Enterprise TE has subsequently negotiated settlements with all but two of the complainants, and the hearing for the remaining complainants is currently scheduled for August 2015. We are unable to predict the outcome of this proceeding.

The initial rates charged to shippers for crude petroleum transportation services from Cushing, Oklahoma to the Gulf Coast on the Seaway Pipeline are being collected subject to refund and to the outcome of an ongoing FERC rate proceeding. Seaway is charging "committed shipper" rates to shippers who voluntarily agreed under long term contracts to commit to the transportation of, or nevertheless to pay for (to the extent not transported) the transportation of, a minimum volume of crude oil. Seaway is also charging "uncommitted shipper" rates to shippers who have not made any long term contractual commitment to the Seaway Pipeline and instead receive service month-to-month. The committed shipper rates are lower than the uncommitted shipper rates and are an incentive to enter into long term transportation agreements.

In March 2013, the FERC issued a declaratory order stating that the charging by a pipeline of voluntarily agreed-to committed shipper rates is consistent with the FERC's policy of honoring contracts (the "March 2013 Order"). In light of the March 2013 Order, we believe that Seaway's committed shipper rates are not at issue in the ongoing rate proceeding, which began in 2012. However, in September 2013, an administrative law judge ("ALJ") issued an initial decision in the rate proceeding (the "Initial Decision") distinguishing the March 2013 Order and recommending that the FERC find, among other things, that Seaway's committed shipper rates are not just and reasonable and should be re-determined on a cost of service basis along with the uncommitted shipper rates.

In October 2013, Seaway and certain committed rate shippers filed briefs on exceptions objecting to this committed shipper rate aspect of the ALJ's Initial Decision, and also challenging various aspects of the cost of service determinations in the Initial Decision. In February 2014, the FERC issued an order reversing the Initial Decision with respect to the committed rate issue, reiterating its policy of honoring contracts executed between pipelines and committed shippers and remanding the remaining issues to the ALJ for further review. In May 2014, the ALJ issued an initial decision on remand, which largely repeated its prior findings, including as to the committed

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shipper rates. Briefs opposing the initial decision on remand were filed in June 2014. We are unable to predict when the FERC will issue an order or the ultimate outcome of this proceeding.

In February 2014, the FERC upheld an order it issued in May 2012 that denied Seaway's initial application for market-based rate setting authority, without prejudice to Seaway refiling its application based on the guidance provided in the February order. In December 2014, Seaway submitted a new application requesting market-based rate setting authority. In light of the fact-intensive and complex nature of these types of market-based rate applications, we are unable to predict the ultimate outcome on the rates Seaway charges its shippers.

Changes in the FERC's methodologies for approving rates could adversely affect us. In addition, challenges to our regulated rates could be filed with the FERC and future decisions by the FERC regarding our regulated rates could adversely affect our cash flows. We believe the transportation rates currently charged by our interstate liquids pipelines are in accordance with the ICA and applicable FERC regulations. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by such pipelines.

Natural Gas Pipelines and Related Matters. Certain of our intrastate natural gas pipelines, including our Texas Intrastate System and our Acadian Gas System, are subject to regulation by the FERC under the Natural Gas Policy Act of 1978 ("NGPA"), in connection with the transportation and storage services they provide pursuant to Section 311 of the NGPA. Under Section 311 of the NGPA, and the FERC's implementing regulations, 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 broader regulatory authority under Natural Gas Act of 1938 ("NGA"). These services must be provided on an open and nondiscriminatory basis, and the rates charged for these services may not exceed a "fair and equitable" level as determined by the FERC in periodic rate proceedings. Our HIOS pipeline is regulated by the FERC under the NGA. The NGA prescribes that transportation rates charged by pipelines be just and reasonable and that service not be provided on an unduly discriminatory basis. Rates may be lowered on a prospective basis by the FERC if it finds, on its own initiative or as a result of challenges to the rates by shippers, that they are unjust, unreasonable or otherwise unlawful.

We believe that the transportation rates currently charged and the services performed by our natural gas pipelines are all in accordance with the applicable requirements of the NGA, the NGPA, and FERC regulations. However, we cannot predict the rates we will be allowed to charge in the future for transportation services by our pipelines.

The resale of natural gas in interstate commerce is subject to FERC oversight. In order to increase transparency in natural gas markets, the FERC has established rules requiring the annual reporting of data regarding natural gas sales. The FERC has also established regulations that prohibit energy market manipulation. The Federal Trade Commission and the Commodity Futures Trading Commission ("CFTC") have also issued rules and regulations prohibiting energy market manipulation. We believe that our gas sales activities are in compliance with all applicable regulatory requirements.

A violation of the FERC's regulations may subject us to civil penalties, suspension or loss of authorization to perform services or make sales of natural gas, disgorgement of unjust profits or other appropriate non-monetary remedies imposed by the FERC. Pursuant to the Energy Policy Act of 2005, the potential civil and criminal penalties for any violation of the NGA, the NGPA, or any rules, regulations or orders of the FERC, were increased to up to $1 million per day per violation.

State Regulation of Pipeline Transportation Services

Transportation services rendered by our intrastate liquids and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Illinois, Kansas, Louisiana, Minnesota, Mississippi, New Mexico, Oklahoma, Texas and Wyoming. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate natural gas transportation operations in Texas. 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 tariff rates and practices on our intrastate pipelines.

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Federal Regulation of Marine Operations

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.

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. As a result of this ownership requirement, 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 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 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. Our marine operations are also subject to the Merchant Marine Act of 1936, which under certain conditions would allow the U.S. government to requisition our marine assets in the event of a national emergency.

Climate Change Debate

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.

In response 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, various governmental authorities have considered or taken actions to reduce emissions of greenhouse gases. For example, the EPA has taken action under the CAA to regulate greenhouse gas emissions. In addition, certain states, including states in which some of our facilities or operations are located, have taken or proposed measures to reduce emissions of greenhouse gases. Also, the U.S. Congress has proposed legislative measures for imposing restrictions or requiring emissions fees for greenhouse gases. However, there have been no federal regulations enacted to date 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. Thus far, negotiations have not resulted in substantive changes that would affect domestic industrial sources of greenhouse gases in the U.S. and it is uncertain whether an international agreement will ever be reached or what the terms of any such agreement would be.

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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 took 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 permit programs beginning in 2011. In 2014, the Supreme Court's decision in Utility Air Regulatory Group v. EPA limited the EPA to include greenhouse gasses in the permitting process only if PSD was already triggered by another listed pollutant. If deemed cost-effective, facilities that trigger permit requirements may be required to reduce greenhouse gas emissions consistent with the "best available control technology" standards. 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 when planning 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.

In January 2015, the White House announced plans to regulate methane emissions attributable to the upstream oil and gas industry, including activities related to gathering and compression, as a greenhouse gas. The EPA has been tasked to publish proposed rules for this matter in 2015, with such rules targeted to go into effect in 2016. Until such proposed rules are developed and published, the impact on our operations is not known; however, it is believed that the only facilities impacted by this proposed rule would be those placed into service after the rules are finalized.

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 federal, regional and state measures generally apply to industrial sources, including facilities in the oil and gas sector, and could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities. These regulations could also adversely affect market demand or pricing for our products or products served by our midstream infrastructure, by affecting the price of, or reducing the demand for, fossil fuels or providing competitive advantages to competing fuels and energy sources. The potential increase in the costs of our operations could include costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay 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.

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 a website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

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We provide free electronic access to our periodic and current reports on our 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.  The information found on our website is not incorporated into this annual report.

Disclosure Under Section 13(r) of the Securities Exchange Act of 1934

Under Section 13(r) of the Securities Exchange Act of 1934, as amended by the Iran Threat Reduction and Syria Human Rights Act of 2012, issuers are required to include certain disclosures in their periodic reports if they or any of their "affiliates" (as defined in Rule 12b-2 thereunder) have knowingly engaged in certain specified activities relating to Iran. Disclosure is required even where the activities are conducted outside the United States by non-U.S. affiliates in compliance with applicable law, and even if the activities are not covered or prohibited by U.S. law.

Dr. F. Christian Flach was named a director of our general partner in October 2014 in connection with the acquisition of Oiltanking. Dr. Flach is also a managing director of Oiltanking GmbH, which maintains a joint venture interest in Oiltanking Odfjell GmbH, which in turn owns a joint venture interest in the Exir Chemical Terminal ("ECT") in Iran. This interest results from an investment dating back to 2002. Oiltanking GmbH currently has the contractual right to vote for the appointment of one member of ECT's three-member board. Oiltanking GmbH provides no goods, services, technology, information or support to ECT and plays no role in the management or day-to-day operations of ECT.

Among other activities, ECT transfers naphtha originating in Iraq to Oman for a customer in the United Arab Emirates. ECT does not import or handle any products originated from Iran that are regulated under U.S., European Union or United Nations sanctions laws. ECT pays routine and standard charges (i) to the Petrochemical Special Economic Zone Organization ("Petzone") for the use of pipelines and (ii) to Terminals and Tanks Petrochemical Co. ("TTPC"), which operates the berth. Petzone and TTPC are subsidiaries of the National Petrochemical Company, which is owned and controlled by the Government of Iran. As Oiltanking GmbH has no direct involvement in the day-to-day operations of ECT, we have no information regarding ECT's intent to continue or not continue making the payments described above.

Oiltanking GmbH maintains an internal compliance program to ensure compliance with all applicable sanctions regimes, including sanctions laws maintained by the United States, European Union and United Nations. Although the existence of the routine payments described above may be reportable under Section 13(r), Oiltanking GmbH has informed us that neither it, nor any of its subsidiaries or affiliates, has engaged in any conduct that would be sanctionable under any of these legal regimes.

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

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. In addition, decreases in demand may be caused by other factors, including

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prevailing economic conditions, reduced demand by consumers for the end products made with hydrocarbon products, increased competition, adverse weather conditions and government regulations affecting prices and production levels. 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.

In recent years, the prices of crude oil and natural gas have been volatile, and we expect this volatility to continue. During the fourth quarter of 2014, crude oil prices based on WTI dropped sharply to a low of $53.27 per barrel, reflecting a decline from an average of $94.20 per barrel in 2012 and $97.97 per barrel in 2013 and a high of $107.26 per barrel earlier in 2014. WTI crude oil prices averaged $47.33 per barrel in January 2015. The New York Mercantile Exchange ("NYMEX") daily settlement price for natural gas for the prompt month futures contract ranged: in 2012, from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu; in 2013, from a high of $4.46 per MMBtu to a low of $3.11 per MMBtu; and in 2014, from a high of $6.15 per MMBtu to a low of $2.89 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, including demand for NGL products by the petrochemical, refining and heating industries; (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 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 the prices of natural gas and NGLs can lead to ethane rejection, which results in lower pipeline and fractionation volumes for our assets. Volatility in these 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.

For further discussion regarding these commodity-related risks together with our current commercial outlook for 2015, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations – Commercial and Liquidity Outlook for 2015 – Commercial Outlook for 2015" included under Part II, Item 7 of this annual report.

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.

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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, 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, 2014, we had $18.95 billion in principal amount of consolidated senior long-term debt outstanding, $1.53 billion in principal amount of junior subordinated debt outstanding and $906.5 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 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, our capital spending for 2014 reflects $6.0 billion of cash payments for capital projects and other investments, including the $2.4 billion paid in connection with Step 1 of the Oiltanking acquisition. Based on information currently available, we expect our total capital spending for 2015 to approximate $3.9 billion, which includes $380 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 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. The success of the Oiltanking acquisition, including the merger that was completed on February 13, 2015, will depend, in part, on our ability to realize the anticipated benefits from combining the businesses of Enterprise and Oiltanking. To realize these anticipated benefits, Enterprise's and Oiltanking's businesses must be successfully combined. If the combined company is not able to achieve these objectives, the anticipated benefits of the merger may not be realized fully or at all or may take longer to realize than expected. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the merger.

Prior to the acquisition, Enterprise and Oiltanking, including their respective subsidiaries, operated independently. It is possible that the integration process could result in the loss of key employees, as well as the disruption of each company's ongoing businesses or inconsistencies in their standards, controls, procedures and policies. Any or all of those occurrences could adversely affect the combined company's ability to maintain relationships with customers and employees after the merger or to achieve the anticipated benefits of the merger. Integration efforts between the two companies will also divert management attention and resources. These integration matters could have an adverse effect on us.

From time to time, we also evaluate and acquire additional 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.

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.

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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A natural disaster, catastrophe, terrorist or cyber 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 or cyber 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 common units.

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, we elected to forego windstorm coverage for our Gulf of Mexico offshore assets during the 2014 Atlantic hurricane season, which extends from June 1 through November 30. The combination of increasingly high deductibles and proposed higher premiums resulted in such coverage being uneconomic to us. Although EPCO's coverage does not provide any windstorm coverage for our offshore assets during the annual policy period that began on June 1, 2014, we expect that producers affiliated with our Independence Hub and Marco Polo platforms will continue to provide certain levels of physical damage windstorm coverage for each of these key offshore assets.

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, 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,

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or our risk management policies and procedures are not followed. Adverse economic conditions, such as the recent rapid declines in crude oil prices during the fourth quarter of 2014 and beginning of 2015, 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 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.

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2014 was Shell, which accounted for 8.5% of our consolidated revenues for the year.

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 variable-rate debt, including those fixed-rate debt obligations that may be 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.

At December 31, 2014, we had $20.48 billion in principal amount of consolidated fixed-rate debt outstanding, including current maturities thereof.  We also had $906.5 million of commercial paper notes

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outstanding at December 31, 2014. Due to the short term nature of commercial paper notes, we view the interest rates charged in connection with these instruments as variable.

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 interest rate swap arrangements, which could increase our exposure to variable interest rates. As a result, significant increases in interest rates could have a material adverse effect on our financial position, results of operations and cash flows. We had no interest rate swap arrangements in place at December 31, 2014.

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 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.

In January 2012, President Obama signed the 2011 Pipeline Safety Act into law. The 2011 Pipeline Safety Act provides, among other things, for additional regulatory 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 "Regulatory Matters—Safety Matters—Pipeline Safety" included 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.

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.

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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 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 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.

Offshore Drilling. Offshore drilling involves additional risks and different regulations than onshore drilling. Since the Deepwater Horizon (or Macondo) oil spill in the Gulf of Mexico during 2010, an event unrelated to our operations, the U.S. Department of Interior (the "Interior Department") and state regulatory authorities have promulgated substantial additional regulations, including regulations relating to the approval of new permits to drill, the enhanced inspections of oil and gas rigs and more stringent preparedness plans. These new regulatory requirements have added, and may continue to add, delays in the permitting of offshore wells and costs in the planning, permitting, development and operation of new and existing wells by our customers. A decline in, or failure to achieve anticipated volumes of oil and natural gas supplies due to any of these factors could have a material adverse effect on our financial position, results of operations and cash flows.

See "Regulatory 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 liquids pipelines under the ICA and our interstate natural gas pipeline under the NGA. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.

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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 Outer Continental Shelf Lands Act 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 comprehensive in scope than regulation by the FERC, our services are typically required to be provided on a nondiscriminatory basis and are also subject to challenge by protest and complaint.

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.

For a general overview of federal, state and local regulation applicable to our assets, see "Regulatory Matters" 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.

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 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 rate changes 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 this indexing methodology, we may also choose to support our rates based on a cost-of-service methodology, or by obtaining advance approval to charge "market-based rates," or by charging "settlement rates" agreed to by all affected shippers. 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.

In addition, the FERC, pursuant to the NGA, and rules and regulations promulgated thereunder, regulates the rates for our interstate natural gas pipeline. 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 the interstate natural gas pipeline are derived and charged based on a cost-of-service methodology.

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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.

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 derivative transactions, including financial and certain physical oil and gas hedging transactions. Under the Dodd-Frank Act, the CFTC has adopted regulations requiring registration of swap dealers and major swap participants, mandatory clearing of swaps, election of the end-user exception for any uncleared swaps by certain qualified companies, recordkeeping and reporting, business conduct standards and position limits among other requirements. Several of these requirements, including position limits rules, allow the CFTC to impose controls that could have an adverse impact on our ability to hedge risks associated with our business and could 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 qualify as an end-user. The vast majority of our derivative transactions are currently transacted through a Derivatives Clearing Organization, therefore use of the end-user exception will likely not be necessary on a routine basis. We will, however, seek to retain our status as an end-user by taking 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. Derivative transactions that are not clearable and transactions that are clearable but for which we choose to elect the end-user exception are subject to recordkeeping and reporting requirements and potentially additional credit support arrangements including cash margin or collateral. 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.

In September 2012, the U.S. District Court for the District of Columbia vacated and remanded the position limits rules adopted by the CFTC based on a necessity finding. In December 2013, the CFTC responded by proposing amended rules in an effort to better conform to the Dodd-Frank Act. Under the proposed rules, the CFTC would place volumetric limitations on transactions in core referenced futures contracts including NYMEX Henry Hub Natural Gas, Light Sweet Crude Oil, New York Harbor Gasoline Blendstock and New York Harbor Heating Oil along with any contracts which are directly or indirectly linked to the price of a core referenced futures contract. These limits include spot month limits leading up to the close of trading for a particular contract and non-spot month limits which would cover all months combined including the spot month. In the proposed rule, the CFTC has provided certain provisions governing Bona Fide Hedges which would enable the exclusion of certain contracts from the calculation of our positions against a given limit. While we believe that the majority of our hedging transactions would meet one or more of the enumerated categories for Bona Fide Hedges, the rules could have an adverse impact on our ability to hedge certain risks associated with our business and could potentially affect our profitability. In 2014, the CFTC reopened the period for public comment on the newly proposed rules, with the most recent comment period closing on January 22, 2015. As of the filing of this annual report, the CFTC has yet to provide final rules.

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 their cash flows to us in order to meet our obligations and to allow us to make cash distributions to our limited partners.

The amount of cash EPO and its subsidiaries and joint ventures can distribute to us depends primarily on cash flows generated from their operations. These operating cash flows fluctuate 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, organizational documents, applicable state business organization laws and other applicable laws and regulations. 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.

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 make cash distributions during periods when we record net income. An inability on our part to pay cash

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distributions to partners could have a material adverse effect on our financial position, results of operations and cash flows.

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

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

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

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

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

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

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

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

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

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

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

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

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

§

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

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

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

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

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

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders did not elect our general partner or its directors and will have no right to elect our general partner or its directors on an annual or other continuing basis. The owners of our general partner choose the directors of our general partner.

Furthermore, if unitholders are dissatisfied with the performance of our general partner, they currently have no practical ability to remove our general partner or its officers or directors. Our general partner may not be removed except upon the vote of the holders of at least 60% of our outstanding units voting together as a single class. Since affiliates of our general partner currently own approximately 35.3% of our outstanding common 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 action under our partnership agreement constituted participation in the "control" of our business. Under Delaware

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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.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to a material amount of federal taxation as an entity. 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 (the highest tax bracket of 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 reduction in the after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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, or an investment in our common units, may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, the Obama Administration and 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. One such Obama Administration budget proposal for fiscal year 2016 would, if enacted, tax publicly traded partnerships with "fossil fuels" activities as corporations for U.S. federal income tax purposes beginning in 2021. 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 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 or proposed Treasury Regulations. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

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

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

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

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

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

If a common unitholder sells common units, the unitholder will recognize a gain or loss equal to the difference between the amount realized in the sale and the unitholder's tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in the unitholder's common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if the unitholder sells such common units at a price greater than the unitholder's tax basis in those common units, even if the price received 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 existing partnership and having formed a new 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 Schedules K-1 if certain relief were unavailable) for one fiscal year and could result in the deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

A 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 SEC 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 will vigorously defend the partnership in litigation matters. Except as set forth below, we are not aware of any material pending legal proceedings at March 2, 2015 to which we are a party, other than routine litigation incidental to our business.

### ETP Matter

In connection with a proposed pipeline project, we and Energy Transfer Partners, L.P. ("ETP") signed a non-binding letter of intent in April 2011 that disclaimed any partnership or joint venture related to such project absent executed definitive documents and board approvals of the respective companies. Definitive agreements were never executed and board approval was never obtained for the potential pipeline project. In August 2011, the proposed pipeline project was cancelled due to a lack of customer support.

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP $319.4 million in actual damages on March 4, 2014. On July 29, 2014, the court entered judgment against us in an aggregate amount of $535.8 million, which includes (i) $319.4 million as the amount of actual damages awarded by the jury, (ii) an additional $150.0 million in disgorgement for the alleged benefit we received due to a breach of fiduciary duties by

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us against ETP and (iii) prejudgment interest in the amount of $66.4 million. The court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5%, compounded annually.

We do not believe that the verdict or the judgment entered against us is supported by the evidence or the law and intend to vigorously oppose the judgment through the appeals process.

Environmental Matters

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 expenditure related to the following matters will be material to our consolidated financial statements.

§ The Texas Commission on Environmental Quality 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 monetary sanctions in excess of $0.4 million.

§ In July 2013, the U.S. Environmental Protection Agency issued a Consent Agreement and Final Order in connection with certain risk management policies at our Mont Belvieu, Texas complex. We believe that the eventual resolution of these matters will result in monetary sanctions of approximately $0.4 million.

§ In January 2014, we paid the State of Texas, acting through the District Attorney's Office in Travis County, Texas, a $1.2 million fine related to environmental compliance and recordkeeping matters at a tractor-trailer repair and washing facility located in Brazoria County, Texas.

§ In August 2014, following a Notice of Violation sent to us in the third quarter of 2013, we received information from the New Mexico Oil Conservation Division that they expect to assess us a penalty in connection with violations involving a hydrostatic test permit for a pipeline project in Santa Fe County, New Mexico. The eventual resolution of these matters may result in monetary sanctions in excess of $0.1 million.

§ In January 2015, the Attorney General of Texas filed litigation against us for Clean Air Act violations resulting from the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. The eventual resolution of these matters may result in monetary sanctions in excess of $0.1 million.

For more information regarding our litigation matters, see "Litigation" 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.

Item 4. Mine Safety Disclosures.

Not applicable.

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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 January 31, 2015, there were approximately 3,000 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 | | |
|---|---|---|---|---|---|
| | | | Per | Record | Payment |
| | High | Low | Unit | Date | Date |
| 2012 | | | | | |
| 1st Quarter | $26.48 | $22.89 | $0.3138 | 04/30/12 | 05/09/12 |
| 2nd Quarter | $26.47 | $22.84 | $0.3175 | 07/31/12 | 08/08/12 |
| 3rd Quarter | $27.49 | $25.39 | $0.3250 | 10/31/12 | 11/08/12 |
| 4th Quarter | $27.69 | $24.26 | $0.3300 | 01/31/13 | 02/07/13 |
| 2013 | | | | | |
| 1st Quarter | $30.17 | $25.51 | $0.3350 | 04/30/13 | 05/07/13 |
| 2nd Quarter | $31.78 | $28.06 | $0.3400 | 07/31/13 | 08/07/13 |
| 3rd Quarter | $32.80 | $28.83 | $0.3450 | 10/31/13 | 11/07/13 |
| 4th Quarter | $33.46 | $29.57 | $0.3500 | 01/31/14 | 02/07/14 |
| 2014 | | | | | |
| 1st Quarter | $35.50 | $31.51 | $0.3550 | 04/30/14 | 05/07/14 |
| 2nd Quarter | $39.26 | $34.52 | $0.3600 | 07/31/14 | 08/07/14 |
| 3rd Quarter | $41.38 | $35.55 | $0.3650 | 10/31/14 | 11/07/14 |
| 4th Quarter | $40.95 | $30.71 | $0.3700 | 01/30/15 | 02/06/15 |

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 foreseeable 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 Issuance of Unregistered Securities

In order to fund the equity consideration paid in Step 1 of the Oiltanking acquisition (see "Acquisition of Oiltanking Partners, L.P." under Part I, Item 1 of this annual report), we issued 54,807,352 common units to OTA on October 1, 2014 in a transaction exempt from the registration requirements of the Securities Act of 1933, as amended (the "Securities Act"), pursuant to Section 4(a)(2) thereof, and we granted OTA registration rights with respect to these common units under a Registration Rights Agreement between us and OTA (the "Registration Rights Agreement"). The Registration Rights Agreement provides that, subject to the terms and conditions set forth therein, at any time after the earlier of (i) 90 days after October 1, 2014 and (ii) the execution of definitive agreements to acquire (through merger or otherwise) all or substantially all of the Oiltanking common units not owned by Enterprise or its affiliates, OTA may request that we prepare and file a registration statement to permit and otherwise facilitate the public resale of all or a portion of the 54,807,352 Enterprise common units that OTA owns.  Our obligation to OTA to effect such transactions is limited to five registration statements and underwritten offerings.

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Common Units Authorized for Issuance Under Equity Compensation Plan

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

Issuer Purchases of Equity Securities

A total of 2,634,074 unit-based awards (e.g., restricted common unit awards granted to key employees of EPCO) vested and were converted to common units during 2014. Of this amount, 894,383 were sold back to us by employees to meet their related tax withholding requirements. The total cost of these repurchased units was $30.2 million. We cancelled such treasury units immediately upon acquisition.

The following table summarizes our repurchase activity during 2014 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 2014 (1) | 842,782 | $ 32.85 | -- | -- |
| May 2014 (2) | 26,386 | $ 36.62 | -- | -- |
| August 2014 (3) | 8,849 | $ 37.52 | -- | -- |
| November 2014 (4) | 16,366 | $ 36.91 | -- | -- |

(1) Of the 2,479,724 restricted common units that vested in February 2014 and converted to common units, 842,782 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 73,800 restricted common units that vested in May 2014 and converted to common units, 26,386 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 32,874 restricted common units that vested in August 2014 and converted to common units, 8,849 units were sold back to us by employees to cover related withholding tax requirements.
(4) Of the 47,676 restricted common units that vested in November 2014 and converted to common units, 16,366 units were sold back to us by employees to cover related withholding tax requirements.

Also, we announced a common unit repurchase program in December 1998 whereby we, together with certain affiliates, could repurchase up to 4,000,000 of our common units on the open market. A total of 2,763,200 common units were repurchased under this program; however, no repurchases have been made since 2002. As of December 31, 2014, we and our affiliates could repurchase up to 1,236,800 additional common units under this program.

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Item 6. Selected Financial Data.

The following table presents selected historical consolidated financial data of our partnership. This information has been derived from and should be read in conjunction with our audited financial statements included under Part II, Item 8 of this annual report, which presents our audited balance sheets as of December 31, 2014 and 2013 and related statements of consolidated operations, comprehensive income, cash flow and equity for the three years ended December 31, 2014, 2013 and 2012, respectively. As presented in the table, amounts are in millions (except dollar per unit data).

| | For the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2011 | 2010 |
| Statements of operations data: | | | | | |
| Total revenues | $47,951.2 | $47,727.0 | $42,583.1 | $44,313.0 | $33,739.3 |
| Total costs and expenses | $44,435.0 | $44,427.0 | $39,538.2 | $41,500.3 | $31,654.1 |
| Equity in income of unconsolidated affiliates | $259.5 | $167.3 | $64.3 | $46.4 | $62.0 |
| Operating income | $3,775.7 | $3,467.3 | $3,109.2 | $2,859.1 | $2,147.2 |
| Net income | $2,833.5 | $2,607.1 | $2,428.0 | $2,088.3 | $1,383.7 |
| Net income attributable to noncontrolling interests | $46.1 | $10.2 | $8.1 | $41.4 | $1,062.9 |
| Net income attributable to limited partners | $2,787.4 | $2,596.9 | $2,419.9 | $2,046.9 | $320.8 |
| Earnings per unit: | | | | | |
| Basic ($/unit) | $1.51 | $1.45 | $1.40 | $1.24 | $0.58 |
| Diluted ($/unit) | $1.47 | $1.41 | $1.35 | $1.19 | $0.58 |
| Cash distributions paid with respect to period ($/unit) | $1.4500 | $1.3700 | $1.2863 | $1.2176 | $1.1350 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2014 | 2013 | 2012 | 2011 | 2010 |
| Balance sheet data: | | | | | |
| Property, plant and equipment, net | $29,881.6 | $26,946.6 | $24,846.4 | $22,191.6 | $19,332.9 |
| Investments in unconsolidated affiliates | $3,042.0 | $2,437.1 | $1,394.6 | $1,859.6 | $2,293.1 |
| Total assets | $47,100.7 | $40,138.7 | $35,934.4 | $34,125.1 | $31,360.8 |
| Long-term debt, including current maturities thereof | $21,363.8 | $17,351.5 | $16,201.8 | $14,529.4 | $13,563.5 |
| Total liabilities | $27,408.5 | $24,698.3 | $22,638.4 | $21,905.8 | $19,460.0 |
| Equity: | | | | | |
| Partners equity | $18,063.2 | $15,214.8 | $13,187.7 | $12,113.4 | $11,374.2 |
| Noncontrolling interests | 1,629.0 | 225.6 | 108.3 | 105.9 | 526.6 |
| Total equity | $19,692.2 | $15,440.4 | $13,296.0 | $12,219.3 | $11,900.8 |
| Limited partner units outstanding (millions) | 1,937.3 | 1,871.4 | 1,797.6 | 1,763.2 | 1,687.4 |

General Discussion of Our Selected Financial Data Since 2010

In general, our results of operations increased from 2010 through 2014 primarily due to increased demand for our products and services, particularly in response to increased hydrocarbon production from supply basins such as the Eagle Ford Shale in South Texas, Permian Basin in West Texas and the Rocky Mountains region. The increase in demand supported our long-term capital spending program. As these projects are completed and commence operations, they contribute additional sources of cash flow to our operating results.

Fluctuations in our consolidated revenues and cost of sales amounts are explained in large part by changes in energy commodity prices. Energy commodity prices fluctuate for a variety of reasons, including supply and demand imbalances and geopolitical tensions. A decrease in our consolidated marketing revenues due to lower energy commodity sales prices may not result in a decrease in operating income or cash available for distribution, since our consolidated cost of sales amounts would also be lower due to comparable decreases in the purchase prices of the underlying energy commodities. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

Our property, plant and equipment balances have increased since 2010 as a result of our capital spending program. For information regarding our capital spending, see "Capital Spending" included under Part II, Item 7 of this annual report.

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Investments in unconsolidated affiliates decreased in 2011 and 2012 primarily due to the liquidation of our investment in Energy Transfer Equity, L.P. ("Energy Transfer Equity"). In general, investments in unconsolidated affiliates have increased since 2012 as a result of cash contributions we made to investees to fund their major capital projects (e.g., Texas Express Pipeline, Front Range Pipeline and the Seaway Pipeline).

Our debt balances have increased since 2010 primarily due to the funding of a portion of our capital spending program using borrowings under bank credit agreements and the issuance of senior notes. Apart from the impact of merger-related changes (such as those described in the following section), our equity balances have also increased over this period due to the funding of our capital spending program using net proceeds from the issuance of common units in connection with underwritten offerings, our distribution reinvestment plan and employee unit purchase plan programs and "at-the-market" program. Additional information regarding our results of operations, liquidity and capital resources and capital spending can be found under Part II, Item 7 of this annual report.

Impact of Holdings Merger on 2010 Selected Financial Data

On September 3, 2010, Enterprise GP Holdings L.P. ("Holdings"), Enterprise, Enterprise GP, Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) and Enterprise ETE LLC ("Holdings MergerCo," a wholly owned subsidiary of Enterprise) entered into a merger agreement (the "Holdings Merger Agreement"). On November 22, 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." 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.

Prior to the merger (the "Holdings Merger"), Enterprise was a consolidated subsidiary of Holdings, which was Enterprise's parent. Upon completion of the Holdings Merger, Holdings merged with and into a wholly owned subsidiary of Enterprise. The Holdings Merger resulted in Holdings being considered the surviving consolidated entity for accounting purposes, while Enterprise was the surviving consolidated entity for legal purposes. From an accounting perspective, Holdings was deemed the acquirer of the noncontrolling interests in Enterprise that were previously recognized in Holdings' consolidated financial statements (i.e., the acquisition of Enterprise's common units and other limited partner interests that were owned by parties other than Holdings). As a result of the Holdings Merger, Enterprise's consolidated financial and operating results prior to November 22, 2010 were presented as if Enterprise was Holdings from an accounting perspective (i.e., the consolidated financial statements of Holdings became the historical financial statements of Enterprise).

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 Enterprise common units based on the 1.5 to 1 exchange ratio. We issued an aggregate 417,626,908 of our common units (net of fractional common units cashed out) as consideration in the Holdings Merger and, immediately after the merger, cancelled 43,126,354 of our common units previously owned by Holdings. Limited partner units outstanding at December 31, 2010 and each subsequent period include both the common units issued to third parties and affiliates since our initial public offering in 1998 and those issued in connection with the Holdings Merger.

Since Holdings regarded third party and affiliate ownership of our common units and other limited partner units as noncontrolling interests prior to the Holdings Merger, net income attributable to limited partners for 2010 is significantly different than the amounts following the Holdings Merger. Net income attributable to limited partners following the Holdings Merger reflects all of our limited partners. Also, basic and diluted earnings per unit data for period prior to the Holdings Merger reflect those reported by Holdings, after retroactively adjusting the amounts to reflect the 1.5 to one unit-for-unit exchange ratio.

Cash distributions per unit presented for 2010 represent the sum of cash distributions declared and paid by Holdings with respect to the first, second and third quarters of 2010 and the cash distribution declared and paid by Enterprise with respect to the fourth quarter of 2010. Cash distributions per unit for 2014, 2013, 2012 and 2011 represent those declared and paid by us with respect to those years.

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

For the Years Ended December 31, 2014, 2013 and 2012

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

Key References Used in this Management's Discussion and Analysis

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

The membership interests of Dan Duncan LLC are owned 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; and (iii) Richard H. Bachmann. 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 privately held Texas corporation, and its privately held affiliates. A majority of the outstanding voting capital stock of EPCO is owned by a voting trust, the current trustees ("EPCO Trustees") of which are: (i) Ms. Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as a Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer ("CEO") of EPCO. Each of the EPCO Trustees is also a director of EPCO.

In addition to owning our general partner, EPCO and its privately held affiliates owned approximately 35.3% of our limited partner interests at December 31, 2014.

References to "Oiltanking" mean Oiltanking Partners L.P. References to "Oiltanking GP" mean OTLP GP, LLC, the general partner of Oiltanking. On October 1, 2014, we acquired Oiltanking GP and the related incentive distribution rights ("IDRs"), 15,899,802 common units and 38,899,802 subordinated units of Oiltanking from Oiltanking Holding Americas, Inc. and its affiliates (collectively, "OTA").

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, 2014 (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

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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.

Overview of Business

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

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the U.S., Canada and Gulf of Mexico with domestic consumers and international markets. Our midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; offshore production platforms; petrochemical and refined products transportation, storage and terminals, and related 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 51,300 miles of onshore and offshore pipelines; 225 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, 22 NGL and propylene fractionators, six offshore hub platforms located in the Gulf of Mexico, a butane isomerization complex, NGL import and LPG export terminals, a refined products export terminal and octane enhancement and high-purity isobutylene production facilities.

On October 1, 2014, we announced our acquisition of the general partner and certain limited partner interests of Oiltanking Partners, L.P. ("Oiltanking"). See "Significant Recent Developments" within this Part II, Item 7 for information regarding this business combination.

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

We have five reportable business segments: (i) NGL Pipelines & Services; (ii) Onshore Natural Gas Pipelines & Services; (iii) Onshore Crude Oil Pipelines & Services; (iv) Offshore Pipelines & Services; and (v) Petrochemical & Refined Products Services. For information regarding our business segments see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Significant Recent Developments

Acquisition of Oiltanking Partners, L.P.

On October 1, 2014, we acquired Oiltanking GP and the related incentive distribution rights, 15,899,802 common units and 38,899,802 subordinated units of Oiltanking from OTA. We paid total consideration of approximately $4.4

billion to OTA comprised of $2.21 billion in cash and 54,807,352 Enterprise common units for these ownership interests and rights. We also paid $228.3 million to assume the outstanding loans, including related accrued interest, owed by Oiltanking or its subsidiaries to OTA.  Collectively, these transactions are referred to as "Step 1" of the Oiltanking acquisition.  We funded the cash consideration for the Step 1 transactions using borrowings under our new $1.5 billion 364-Day Credit Agreement, proceeds from the sale of short-term notes under our commercial paper program and cash on hand.

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Oiltanking owns marine terminals located on the Houston Ship Channel and at the Port of Beaumont with a total of 12 ship and barge docks and approximately 26 MMBbls of crude oil and petroleum products storage capacity. Oiltanking's marine terminal on the Houston Ship Channel is connected by pipeline to our Mont Belvieu, Texas complex and is integral to our growing LPG export, crude oil storage and octane enhancement and propylene businesses. Our Enterprise Crude Houston ("ECHO") facility is also connected to Oiltanking's system. We have had a strategic relationship and enjoyed mutual growth with Oiltanking and its predecessors since 1983. The combination of our legacy midstream assets and Oiltanking's access to waterborne markets and crude oil and petroleum products storage assets extends and broadens our midstream energy services business. We believe this combination benefits our producing and consuming customers by enhancing their respective access to supplies, domestic and international markets, and storage.

Following Step 1 of the Oiltanking acquisition, but not part of Step 2 of the acquisition, on November 17, 2014, the 38,899,802 Oiltanking subordinated units held by Enterprise automatically converted into an equal number of Oiltanking common units pursuant to the terms of the Oiltanking partnership agreement. Following this conversion, Enterprise owned 54,799,604 Oiltanking common units, or approximately 65.9% of Oiltanking's outstanding common units.

As a second step of the Oiltanking acquisition (separately negotiated by the conflicts committee of Oiltanking's general partner on behalf of Oiltanking), we entered into an Agreement and Plan of Merger (the "merger agreement") with Oiltanking on November 11, 2014 that provided for the following:

§ the merger of a wholly owned subsidiary of Enterprise with and into Oiltanking, with Oiltanking surviving the merger as a wholly owned subsidiary of Enterprise (the "Oiltanking Merger"); and

§ all outstanding common units of Oiltanking at the effective time of the merger held by Oiltanking's public unitholders (which consist of Oiltanking unitholders other than Enterprise and its subsidiaries) to be cancelled and converted into Enterprise common units based on an exchange ratio of 1.30 Enterprise common units for each Oiltanking common unit.

In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including Enterprise's ownership interests representing approximately 65.9% of Oiltanking's outstanding common units) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,557 Enterprise common units were issued to Oiltanking's former public unitholders. After taking into account the aggregate value of consideration issued and paid in the Oiltanking acquisition, our total cost to acquire Oiltanking was approximately $5.9 billion.

In connection with Step 1 of the transaction, we entered into a Liquidity Option Agreement with OTA and Marquard & Bahls ("M&B"), an affiliate of OTA. Pursuant to the Liquidity Option Agreement, we granted M&B the option (the "Liquidity Option") to sell to Enterprise 100% of the issued and outstanding capital stock of OTA (the "Option Securities") at any time within a 90-day period commencing on February 1, 2020. At that time, OTA's only significant asset would be the Enterprise common units it received in Step 1, to the extent that such common units are not sold by M&B prior to the Liquidity Option exercise date. If this put option is exercised, the aggregate consideration to be paid by us for the Option Securities would equal 100% of the then-current fair market value of the OTA-owned Enterprise common units at the closing of the transactions contemplated under the Liquidity Option Agreement. The fair market value would be determined by multiplying the number of Enterprise common units owned by OTA at the time of exercise by the volume-weighted sales price per unit of Enterprise common units as reported by the NYSE (or other national securities exchange, as applicable) for the ten (10) consecutive trading days preceding the exercise. The consideration paid may be in the form of newly issued Enterprise common units, cash or any mix thereof, as determined solely by us. The Liquidity Option Agreement contains indemnification by M&B for certain specified

liabilities of OTA following the closing of any exercise of the Liquidity Option, and certain conditions to closing.
If a defined "Trigger Event" occurs, the Liquidity Option may be exercised earlier within a 135-day period following notice of such event. The aggregate consideration to be paid by us for the Option Securities in connection
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with an exercise of the option due to a Trigger Event will be solely cash, determined in the same manner as the price otherwise payable upon the exercise of the Liquidity Option in the absence of a Trigger Event.

See "Recent Issuance of Unregistered Securities" under Part II, Item 5 for information regarding a registration rights agreement we entered into in connection with the 54,807,352 common units issued as consideration in Step 1 of the Oiltanking acquisition.

OTA is wholly owned by an affiliate of Oiltanking GmbH, an independent storage provider for crude oil, refined products, liquid chemicals and gases headquartered in Hamburg, Germany. Dr. F. Christian Flach, managing director of Oiltanking GmbH and former chairman of the board of Oiltanking, was named as a director of our general partner in connection with our acquisition of Oiltanking. For additional information regarding Dr. Flach, see Part III, Item 10 of this annual report.

As a result of our acquisition of Oiltanking GP, we began consolidating the financial statements of Oiltanking and its general partner on October 1, 2014. This business combination was accounted for using the acquisition method of accounting. This method requires us to allocate the cost of a business combination to the assets acquired and liabilities assumed based on their estimated fair values on the transaction date. For information regarding our accounting for this business combination, see Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena Duces Tecum from the Federal Trade Commission requesting specified information relating to the Oiltanking acquisition. We are in the process of complying with the requests and are cooperating with the investigation. Based on the limited information that Enterprise has at this time, we are unable to predict the outcome of the investigation.

Expansion of Eagle Ford Crude Oil Pipeline System

In November 2014, we, along with Plains All American Pipeline, L.P. ("Plains") announced an expansion of our Eagle Ford Crude Oil Pipeline System in South Texas. The expansion project entails the construction of a new 55-mile crude oil gathering system that will connect Karnes County and Live Oak County production areas in Texas to the joint venture's Three Rivers, Texas terminal. The joint venture will also construct an additional 70-mile, 20-inch pipeline from Three Rivers to Corpus Christi, Texas as well as expand storage and pumping capacity at Three Rivers. When combined with the expansion project announced in September 2013, this project effectively loops the Eagle Ford Crude Oil Pipeline System from Gardendale, Texas to Corpus Christi and increases the system's capacity to transport light and medium grades of crude oil to over 600 MBPD. These expansions are supported by a long-term production commitment and are expected to be placed into service in the third quarter of 2015.

Plains and Enterprise will also construct a new deep water terminal on the Corpus Christi ship channel to support the expected increase in crude oil volumes to be shipped via pipeline to the region. The dock is being designed to handle a variety of ocean-going vessels and is planned to be in service by 2017.

Plans to Construct Additional Midstream Infrastructure to Serve the Delaware Basin

In September 2014, we announced plans to construct a new cryogenic natural gas processing plant in Eddy County, New Mexico and associated natural gas and NGL pipeline infrastructure to facilitate growing production of NGL-rich natural gas in the Delaware Basin, a prolific production area in West Texas and southern New Mexico. These assets are expected to begin operations in the first quarter of 2016. The South Eddy natural gas processing plant is expected to have an initial capacity of 200 MMcf/d of natural gas, with the potential for future expansions. Upon completion, this will bring our total natural gas processing plant capacity in the Delaware Basin to 400 MMcf/d.

To supply the new South Eddy plant, we plan to construct approximately 80 miles of natural gas gathering pipelines to complement our existing 1,500 miles of natural gas gathering pipelines located in the Delaware Basin. We also expect to build a 75-mile, 12-inch diameter NGL pipeline to transport NGLs from the South Eddy plant to our Hobbs NGL fractionation and storage facility located in Gaines County, Texas. As a result of multiple pipeline

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connections at our Hobbs facility, shippers will have access to our NGL fractionation and storage complex in Mont Belvieu, Texas. Additionally, we plan to deliver residue gas from the South Eddy plant through new interconnections with existing third party pipelines.

Initial Stage of Aegis Ethane Pipeline Completed

In September 2014, we announced that the first segment, or 60 miles, of our Aegis Ethane Pipeline was complete and ready to commence ethane deliveries between our Mont Belvieu storage complex and Beaumont, Texas. The 270-mile Aegis Ethane Pipeline (or "Aegis") represents a key component of our planned ethane header system stretching from Corpus Christi, Texas to the Mississippi River in Louisiana. After taking into account existing South Texas midstream infrastructure and completion of the first segment of Aegis, this 500-mile ethane header system is now in service from Corpus Christi to Beaumont. The remainder of Aegis will be completed in two phases. The next segment between Beaumont and Lake Charles, Louisiana is expected to be completed in the third quarter of 2015. The final segment from Lake Charles to the Mississippi River is expected to be completed by the end of 2015.

Plans to Build Ninth NGL Fractionator at Our Mont Belvieu, Texas Complex

In September 2014, we announced plans to build a ninth NGL fractionator adjacent to our complex in Mont Belvieu, Texas. If constructed, the ninth fractionator is expected to have a capacity of 85 MBPD. We have secured the required permits and emission credits for the ninth and a possible, similarly-sized tenth NGL fractionator at Mont Belvieu. We are evaluating the timing of these projects in light of current business conditions.

SEKCO Oil Pipeline Completed

The SEKCO Oil Pipeline was completed in July 2014, with crude oil shipments starting in January 2015 when the Lucius oil and gas field commenced operations. The SEKCO Oil Pipeline is owned by Southeast Keathley Canyon Pipeline Company, L.L.C., which is owned 50% by us and 50% by Genesis Energy, L.P. The SEKCO Oil Pipeline is a 149-mile crude oil gathering pipeline serving producers in the Lucius oil and gas field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico. The new pipeline connects the third party-owned Lucius-truss spar floating production platform to an existing junction platform at South Marsh Island 205, which is part of our Poseidon Oil Pipeline System. We serve as operator of the SEKCO Oil Pipeline, which has a capacity of 115 MBPD.

Seaway Crude Oil Pipeline Loop Completed

In June 2014, Seaway Crude Pipeline Company LLC ("Seaway") completed a pipeline looping project involving its Longhaul System. This expansion project included the construction of an additional 512-mile, 30-inch pipeline that transports crude oil south from the Cushing hub to Seaway's Jones Creek terminal. With the looping project complete, the aggregate transportation capacity of the Longhaul System is approximately 850 MBPD, depending on the type and mix of crude oil being transported and other variables. Crude oil deliveries using the new pipeline (referred to as the "Seaway Pipeline looping project") commenced in December 2014.

Seaway's Jones Creek terminal is connected to our ECHO crude oil storage facility located in Houston, Texas by a 65-mile, 36-inch pipeline. Construction of a 100-mile, 30-inch pipeline from ECHO to Beaumont/Port Arthur, Texas, was also completed in July 2014. These new pipeline construction projects complement ongoing expansion activities at ECHO, which include the completion of three new storage tanks during the second quarter of 2014.

Marine Terminal Begins Exporting Refined Products

In May 2014, we began loading cargoes of refined products for export on our reactivated marine terminal in Beaumont, Texas, and within six months the facility was sold out. Located on the Neches River, the terminal can load at rates up to 15,000 barrels per hour. The facility includes a dock with a 40-foot draft that can accommodate Panamax size vessels that have a capacity of up to 400,000 barrels. The terminal has access to more than 12.0 MMBbls of refined products storage and receives products from eight refineries, representing approximately 3.3

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MMBPD of capacity, as well as the Colonial Pipeline.

The costs for improvements and modifications required to resume operations at the terminal, which included channel dredging, new pipeline construction, and the installation of new loading arms and vapor recovery systems, are supported by long-term customer commitments. Ongoing expansion of the Beaumont refined products terminal, also supported by long-term customer commitments, includes significant additional on-site storage and ancillary equipment for gasoline blending operations. With its strategic location and enhanced capabilities, the Beaumont marine terminal provides optionality for customers, allowing them to capture added value from the evolving fundamentals of the domestic and international refined products markets.

Plans to Construct Ethane Export Facility on Houston Ship Channel

In April 2014, we announced plans to construct a fully refrigerated ethane export facility on the U.S. Gulf Coast. The new facility, which is located on the Houston Ship Channel, is expected to have an aggregate loading rate of approximately 10,000 barrels per hour and is supported by long-term contracts. We expect the ethane export facility to begin operations in the third quarter of 2016.

Our ethane export facility will provide new markets for domestically-produced ethane, and will assist U.S. producers in increasing their associated production of natural gas and crude oil. We estimate that U.S. ethane production capacity currently exceeds U.S. demand by 300 MBPD and could exceed demand by up to 700 MBPD by 2020, after considering the estimated incremental demand from new ethylene facilities that have been announced.

The ethane export facility will be integrated with our Mont Belvieu complex. Our Mont Belvieu complex receives NGL supplies from several major producing basins across the U.S., including the Marcellus and Utica Shales via our recently completed Appalachia-to-Texas Express ("ATEX") ethane pipeline. We believe that our integrated NGL system offers supply assurance and diversification for the ethane export facility.

Front Range Pipeline Begins Operations

Our Front Range Pipeline commenced operations in February 2014. This 435-mile pipeline transports NGLs originating from the Denver-Julesburg production basin in Weld County, Colorado to Skellytown, Texas in Carson County. With connections to our Mid-America Pipeline System and Texas Express Pipeline, the Front Range Pipeline provides producers in the Denver-Julesburg basin with access to the Gulf Coast, which is the largest NGL market in the U.S. Initial throughput capacity for the Front Range Pipeline is 150 MBPD, which could be expanded to approximately 230 MBPD with certain system modifications. The Front Range Pipeline is owned by Front Range Pipeline LLC, which is a joint venture among us and affiliates of DCP Midstream Partners LP and Anadarko Petroleum Corporation. We operate the Front Range Pipeline and own a one-third member interest in Front Range Pipeline LLC.

ATEX Pipeline Begins Operations

Our ATEX pipeline, which commenced operations in January 2014, transports ethane primarily southbound from NGL fractionation plants located in Pennsylvania, West Virginia and Ohio to our Mont Belvieu storage complex. The ethane extracted by these fractionation facilities originates from the Marcellus and Utica Shale production areas. In addition to newly constructed pipeline segments, significant portions of the ATEX pipeline consist of segments that were formerly used in refined products transportation service by our TE Products Pipeline. Initial throughput capacity for the ATEX pipeline is 125 MBPD, which could be expanded to approximately 265 MBPD with certain system modifications.

ATEX terminates at our Mont Belvieu storage facility, which includes an extensive pipeline distribution system. With the addition of our Aegis Ethane Pipeline, we will, through our Mont Belvieu facilities, link Marcellus and Utica Shale-produced ethane to existing ethylene production facilities along the U.S. Gulf Coast and provide supply security to support construction of new third party ethylene plants currently planned in Texas and Louisiana.

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Expansion of Houston Ship Channel LPG Export Terminal

We provide customers with LPG export services at our marine terminal located on the Houston Ship Channel. This terminal has the capability to load cargoes of fully refrigerated, low-ethane propane and/or butane onto multiple tanker vessels simultaneously. In March 2013, we completed an expansion project at this terminal that increased its loading capability from 4.0 MMBbls per month to 7.5 MMBbls per month. Our LPG export services continue to benefit from increased NGL supplies produced from domestic shale plays such as the Eagle Ford Shale and strong international demand for propane as a feedstock in ethylene plant operations and for power generation and heating purposes.

In September 2013, we announced an expansion project at this LPG export terminal that is expected to increase its ability to load cargoes from 7.5 MMBbls per month to approximately 9.0 MMBbls per month. This expansion project is expected to be completed in the first quarter of 2015.

In January 2014, we announced a further expansion of this LPG export terminal that is expected to increase its ability to load cargoes from approximately 9.0 MMBbls per month to in excess of 16.0 MMBbls per month. Once this expansion project is completed, we expect our maximum loading capacity at this export terminal will be approximately 27,000 barrels per hour. The expanded LPG export terminal is expected to be in service by the end of 2015 and is supported by long-term LPG export agreements.

Mid-America Pipeline System's Rocky Mountain Expansion Project Begins Operations

In January 2014, we announced the completion of an expansion project involving the Rocky Mountain pipeline of our Mid-America Pipeline System. This expansion project involved looping 265 miles of the Rocky Mountain pipeline, as well as related pump station modifications, which increased transportation capacity on the pipeline from approximately 275 MBPD to 350 MBPD. This expansion project was built to accommodate growing natural gas and NGL production from major supply basins in Colorado, New Mexico, Utah and Wyoming.

Commercial and Liquidity Outlook for 2015

Commercial Outlook for 2015

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

As a result of significant advances in non-conventional drilling and production technology, North American reserves and production of hydrocarbons from shale developments have increased substantially. The rapid increase in U.S. hydrocarbon supplies has led to a reduction in imports of crude oil, NGLs, refined products and natural gas into the U.S. Conversely, this trend has also resulted in significant increases in hydrocarbon exports from the U.S., particularly of refined products and LPGs, and contributed to price volatility in the price of natural gas and NGLs, especially of ethane.

In the summer and fall of 2014, oil economists, including those at the International Energy Agency, began to express concerns about a growing global excess of crude oil and refined products in light of a weaker global economic outlook (especially for Europe and China) and in the face of surging supplies from the U.S. as well as production growth from Iraq, Libya, Iran and certain African countries. In the fall of 2014, the market began to see signals of growing crude oil inventories coupled with unusual monthly discounts from OPEC nations to certain markets in order to retain their market share. On November 27, 2014, OPEC met for a regularly scheduled meeting and could not agree to cut their crude oil production in order to stabilize global oil prices. In addition to not cutting production, as part of the November meeting, Saudi Arabia indicated that it believed that market forces, rather than OPEC's self-imposed quotas, should determine global oil prices. As a result of no production cuts from OPEC and the strong communication from Saudi Arabia, oil prices rapidly deteriorated, falling quickly from approximately $75 per barrel to $45 per barrel by the end of January 2015.

The collapse in crude oil prices is impacting market dynamics for hydrocarbons around the world, resulting in uncertainty in supply and demand fundamentals for crude oil, refined products, NGLs, natural gas and other energy-intensive products including petrochemicals. While it is impossible to predict exactly how lower energy commodity prices will impact us in 2015, we expect that an extended period of significantly lower crude oil and NGL prices will slow drilling activity in the regions we serve, which ultimately could reduce the overall supply of crude oil, natural gas and NGLs available to our facilities. While all domestic production basins are expected to be impacted in 2015, we expect the largest reductions in drilling activity will be in domestic supply basins located farthest from the U.S. Gulf Coast.

Although the exact impact of drilling and well completions is uncertain, we currently believe that producers will remain focused on the Eagle Ford Shale and Permian Basin regions because of their favorable returns on capital and relative close proximity to Gulf Coast markets, which increases their net operating cash flows compared to other more distant producing regions. It is too early to predict how drilling programs in other plays farther from the Gulf Coast will be impacted, but we expect that many basins that have lower returns on capital due to higher transportation costs will likely experience a significant reduction in drilling activity until crude oil, NGL and natural gas prices improve. Many producers have indicated that they expect to negotiate reductions in their drilling and completion costs to help mitigate some of the impact from energy commodity falling prices. Nevertheless, many producers are indicating that they expect their production to continue to increase in 2015 compared to 2014 as they work through significant completion backlogs and drilling/contractual commitments and rely on financial hedges to help support their near-term cash flow needs. Once these backlogs and commitments are satisfied and any financial hedges settle, producers are generally uncertain about their post-2015 drilling and production plans in light of the current commodity price environment.

Lower energy commodity prices for an extended period of time could lead to significant and prolonged reductions in drilling activity that would eventually result in lower production volumes and could negatively impact our gross operating margins relative to natural gas processing, pipeline operations and NGL fractionation, and could also adversely affect regional price spreads that could lower results from our marketing activities. In addition, lower energy commodity prices over an extended period of time could contribute to a decrease in our capital spending for new assets or expansion opportunities for existing assets. Certain producers have already announced significant reductions in their capital budgets and production plans for 2015, and others have said that they are in the process of revising their 2015 capital budgets in light of the decline in crude oil prices. Furthermore, producers that have published capital spending and production estimates for 2015 have, in general, noted that they are subject to change as the current situation develops.

In contrast to the negative impacts on energy producers, lower energy costs could lead to an increase in energy consumption and an increase in investments in energy intensive industries (e.g., steel manufacturing and industrial chemicals) as lower energy costs reduce the variable costs of such industries and improve investment returns of some projects. An increase in demand for crude oil or NGLs from these types of industries, along with other positive consumer-driven demand responses to the lower prices, may help to balance crude oil supply and demand fundamentals by the end of 2015. Regardless of such market dynamics, almost all of the assets we have under construction or have recently completed, whether supply or end-use oriented, are backed by significant long-term fee-based commitments from shippers and/or end-use customers. In addition, many of our recent pipeline projects are backed by contractual volume commitments over the next several years (e.g., shipper commitments on our ATEX, Texas Express and Front Range pipelines), thus providing support to the cash flows generated by these assets. For additional information regarding our recent significant projects, see "Significant Recent Developments" within this Part II, Item 7.

Natural gas has been trading at a significant discount to crude oil for the last several years due to changes in supply and demand fundamentals and, in spite of the recent downturn in crude oil prices, natural gas continues to trade at a significant discount relative to historical norms. For example, on an energy-equivalent basis, natural gas prices for 2015 are forecast to be 30% to 36% of the price of crude oil (based on prices quoted in futures markets in January 2015). For 2014 and 2013, natural gas was priced at 27% and 22% of crude oil on an energy-equivalent basis, respectively. In addition, ethane prices have decreased over time in terms of price per gallon and as a percentage relative to the price of crude oil on an energy-equivalent basis. The decline in ethane prices is attributable to excess domestic supply. For example, the average price of ethane in 2012 was $0.40 per gallon (or 37% of the relative price of crude oil on an energy-equivalent basis). The average price of ethane continued to decline in 2013,

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decreasing to $0.26 per gallon (or 23% of the relative price of crude oil on an energy-equivalent basis) and averaged $0.27 per gallon (or 25% of the relative price of crude oil on an energy-equivalent basis) in 2014. At the end of January 2015, ethane was priced at $0.18 per gallon (or 36% of the relative price of crude oil on an energy-equivalent basis).

As a result of these natural gas and ethane price trends, producers have significantly decreased their drilling activity in onshore areas where natural gas production is considered "dry" or "lean" (i.e., the amount of NGLs produced in connection with the natural gas production is relatively small) and have focused more on NGL-rich natural gas and crude oil developments over the last several years. A similar trend is also occurring in the Gulf of Mexico, with producers investing capital to develop new sources of crude oil production rather than areas where natural gas production is prevalent. In general, the focus on crude oil and NGL-rich supply basins by producers has contributed to significant increases in domestic production of these hydrocarbons. The excess supply and inventories have led to lower prices for these energy commodities and contributed to a global focus on exports of U.S. hydrocarbons, to the extent such exports are permitted by U.S. governmental authorities.

U.S. LPG exports continue to increase as a result of ample supplies, increased export capacity and competitive prices as compared to international markets. Overall, U.S. propane waterborne exports increased from approximately 153 MBPD in 2012 to 288 MBPD in 2013 and to 403 MBPD in 2014. Markets in Central and South America have been the major source of new demand for U.S. LPG exports; however, volumes are also being transported to Northwest Europe and Far East Asia. LPG exports from the U.S. Gulf Coast to Central and South America are expected to increase in the future. Similarly, greater volumes of Gulf Coast-sourced LPGs are expected to reach Asian markets after the anticipated Panama Canal expansion is completed (currently forecast for early 2016). This expansion project is expected to make LPG exports from the Gulf Coast to Asia more economical for shippers, allowing Asian importers to further diversify their sources of LPGs beyond their traditional Middle East suppliers. In 2014, U.S. ethane exports were generally limited to petrochemical customers in Canada that could receive volumes by pipeline.

Due to the renewed focus on hydrocarbon exports, we are actively growing our ability to provide services and products to Gulf Coast exporters. We are currently the largest supplier of propane to such exporters, and are nearly doubling the LPG export capacity at our Houston Ship Channel terminal over the next 18 months. In April 2014, we commenced construction of a large-scale marine ethane export facility, which will be located at Morgan's Point on the Houston Ship Channel. Our ethane export dock will be strategically linked to our Mont Belvieu storage, fractionation and pipeline assets. The construction and operation of the ethane export dock is supported by long-term commitments for approximately 80% of the facility's projected capacity and several customers have expressed interest in the remaining capacity and possible expansions.

In May 2014, we began loading cargoes of refined products for export on our reactivated marine terminal in Beaumont, Texas. We are also expanding this terminal with additional on-site storage and ancillary equipment for gasoline blending operations. Reactivation of the terminal, as well as its expansion, was supported by long-term customer commitments. With its strategic location and enhanced capabilities, the Beaumont Refined Products Export Terminal provides optionality for exporters, allowing them to capture added value from the evolving fundamentals of the domestic and international refined products markets.

In October 2014, we completed Step 1 of the Oiltanking acquisition (see "Significant Recent Developments" within this Part II, Item 7). In February 2015, the Oiltanking Merger was completed. The combination of our legacy midstream assets and Oiltanking's access to waterborne markets and crude oil and petroleum products storage assets extends and broadens our midstream energy services business. We believe this combination benefits our producing and consuming customers by enhancing their respective access to supplies, domestic and international markets, and storage.

In recent years, natural gas and NGLs developed a significant feedstock price advantage over more costly crude oil derivatives (such as naphtha).  We expect this trend to continue based on energy prices quoted on futures markets in January 2015 and due to: (i) ongoing production from domestic shale resource plays and efforts by producers to lower associated drilling costs; (ii) anticipated increases in demand for crude oil by China, India and other developing economies; and (iii) geopolitical risks in many areas of the world that are major exporters of crude oil, which may cause unexpected crude oil price increases.  In addition, this trend is supported in the near term by a

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lack of meaningful infrastructure to export natural gas and ethane supplies from the U.S., which results in an oversupply and lower market values for both energy commodities.

As a result of the feedstock price advantage currently held by natural gas and NGLs, energy consumers in the industrial manufacturing and power generation sectors are continuing to adjust their feedstock and asset portfolios to consume increasing amounts of these commodities in their operations. In addition, we believe the feedstock price advantage of domestically-produced NGLs has led to a long-term fundamental change in feedstock selection by the U.S. petrochemical industry, which is the largest consumer of domestic NGLs. Since NGLs typically trade at a significant discount to crude oil, using NGLs as a feedstock generally provides a substantial cost advantage for U.S. petrochemical companies when compared to using naphtha, whose price is closely linked to international crude prices. From 2009 through 2014, ethane and propane have generally been the most profitable feedstocks in the production of ethylene. In order to capitalize on this cost advantage, U.S. petrochemical companies have maximized their consumption of domestic NGLs, particularly ethane, in the production of ethylene. Many of these companies have also announced plans to invest billions of dollars to construct NGL feedstock-oriented, world-scale ethylene plants on the Gulf Coast. For example:

§ CP Chemical announced in December 2011 that it expects to build a 1.5 million metric tons per year ethylene plant in Cedar Bayou, Texas by 2017;

§ Formosa Plastics announced in March 2012 that it expects to build an 800 thousand metric tons per year ethylene plant along the U.S. Gulf Coast by 2016/2017;

§ Dow Chemical announced in April 2012 that it expects to build a 1.5 million metric tons per year ethylene plant along the U.S. Gulf Coast by 2017;

§ Sasol announced in October 2014 that they had reached final approval to build a 1.5 million metric ton per year ethylene plant in Lake Charles Louisiana; and

§ numerous other petrochemical companies have announced significant expansions and or conversions to ethane for at existing facilities.

Almost all of these ethylene plants and the ethylene industry's major expansions are in close proximity to our existing or planned assets, including our Aegis Ethane Pipeline.

Based on industry publications, domestic production of ethylene in 2014 was estimated to be 145 million pounds per day compared to 148 million pounds per day in 2013. Ethane is the most widely used feedstock by the U.S. petrochemical industry in the production of ethylene. As a result, ethane consumption by domestic petrochemical companies has, at times, been in excess of 1.1 MMBPD. We believe the U.S. ethylene industry could consume approximately 200 MBPD of additional ethane feedstocks over the next few years through modifications, debottlenecking and expansions at existing facilities. In addition, we believe that announced new petrochemical plant construction projects, including those noted in the preceding paragraph, could consume well over 500 MBPD of additional ethane feedstocks when completed. However, for almost all of 2014, ethane production was in excess of the ethylene industry's ability to consume ethane, resulting in significant volumes of ethane not being extracted from the natural gas stream by producers and natural gas processors in an effort to balance ethane supply to demand. In the absence of additional near-term demand growth or a significant drop in production, we expect ethane to remain oversupplied. This could lower the value of our equity NGL production and reduce the volumes that would otherwise be handled by our downstream NGL fractionators and pipelines.

Drilling activity in shale plays with predominantly dry natural gas production or natural gas production with a lower NGL content (e.g., the Haynesville/Bossier, Barnett, Fayetteville, Piceance and Jonah/Pinedale shales) are expected to remain well below peak levels. As a result, we expect that natural gas volumes on pipelines that serve these supply basins, including our Jonah, Piceance Basin, San Juan and Haynesville gathering systems, may decline further in 2015 when compared to 2014. Although these supply basins are currently experiencing production declines, we believe that these areas have substantial, undeveloped natural gas reserves with some of the lowest development and production costs in the U.S. Furthermore, we believe that as U.S. supply and demand for natural gas and ethane becomes more balanced through exports of these commodities and, as a result, natural gas

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and ethane prices stabilize and increase, these supply basins could experience an increase in drilling activity to support, and potentially increase, their future production levels.

With respect to the Gulf of Mexico, we expect that transportation volumes on our offshore crude oil pipelines will continue to increase in the near term as significant deepwater prospects begin production. For example, our SEKCO Oil Pipeline, which serves the Lucius field located in the southern Keathley Canyon area of the deepwater central Gulf of Mexico, commenced operations during the first quarter of 2015. Conversely, we expect that throughput volumes on our offshore Gulf of Mexico natural gas pipelines will continue to decline in 2015 due to producers focusing more of their near-term resources to exploit offshore crude oil developments and onshore NGL-rich natural gas and crude oil producing areas; however, increases in natural gas production associated with oil production are expected to temper the overall decline in Gulf of Mexico natural gas production. Development of hydrocarbon reserves in the Gulf of Mexico is capital intensive and projects typically have long lead times. At this time, we are uncertain what, if any, effect the current environment of lower hydrocarbon prices will have on producers' intermediate plans to explore and develop reserves in the Gulf of Mexico.

As a result of crude oil pipeline infrastructure expansions, including the Seaway Pipeline looping project we placed into service in 2014, producers have greater access to U.S. Gulf Coast refineries. This is evident in a significant narrowing of the differential in 2014 between Light Louisiana Sweet ("LLS") and West Texas Intermediate ("WTI"), which saw the premium of LLS compared to WTI (based on their average indicative price spread) narrow from $9.35 per barrel in 2013 to $3.61 per barrel in 2014 and $1.56 per barrel at the end of January 2015. The narrowing of the premium was a direct result of over 1.2 MMBPD of new pipeline capacity being placed into service between the Cushing hub and the U.S. Gulf Coast in 2014. With approximately 8.5 MMBPD of refining capacity along the Gulf Coast, refiners now have access to a wide array of crude types from which to choose, and will vary their crude input stream by employing a mix of domestic production with waterborne imports in order to optimize their operations and profitability. As a result of increasing domestic supplies, the U.S. Gulf Coast has seen crude oil imports fall from 3.7 MMBPD in 2013 to 3.4 MMBPD in 2014, while refinery crude runs on the Gulf Coast increased from 8.1 MMBPD in 2013 to 8.3 MMBPD in 2014. Many domestic refineries are modifying and expanding their facilities in order to process more North American crude oil and are also increasing their refined product exports in order to capture market share in emerging economies, which typically have insufficient refining capacity to satisfy their growing demand. We believe that this increased reliance on domestically-produced crudes will continue in 2015, with refiners further reducing their imports of waterborne crudes (particularly "light sweet" crudes). This trend should have a beneficial impact on our crude oil pipeline and storage assets and our refined product export facilities in 2015; however, this outlook may be compromised if there is a prolonged reduction in domestic crude oil drilling and production, or if overseas crude markets become discounted compared to the U.S. Gulf Coast for an extended period.

Liquidity Outlook for 2015

At December 31, 2014, we had $4.17 billion of consolidated liquidity, which was comprised of $74.4 million of unrestricted cash on hand and $4.09 billion of available borrowing capacity under EPO's revolving credit facilities. Throughout 2014, the corporate debt and equity capital markets were accessible to us, along with adequate credit availability from banks. Based on current market conditions (as of the filing date of this annual report), we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs for the reasonably foreseeable future.

We have $2.05 billion of senior notes maturing in 2015 through the first quarter of 2016. We expect to refinance these senior note obligations at or prior to their maturity. The U.S. government is expected to continue to run substantial annual budget deficits in the coming years that will require a corresponding issuance of debt by the U.S. Treasury. The interest rate on U.S. Treasury debt has a direct impact on the cost of our debt. At this time, we are uncertain what impact the expected large issuances of U.S. Treasury debt and the prevailing economic and capital market conditions during these future periods will have on the cost and availability of capital, and we have not executed any interest rate swaps to hedge a portion of our expected future debt issuances in connection with the refinancing of debt. We continue to monitor and evaluate the condition of the capital markets and our interest rate risk with respect to refinancing these maturities and funding our capital spending program.

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For information regarding our capital spending program, including projected 2015 spending levels, see "Capital Spending" within this Part II, Item 7.

Results of Operations

Summarized Consolidated Income Statement Data

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

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| Revenues | $47,951.2 | $47,727.0 | $42,583.1 |
| Costs and expenses: | | | |
| Operating costs and expenses: | | | |
| Cost of sales | 40,464.1 | 40,770.2 | 36,015.5 |
| Other operating costs and expenses | 2,541.8 | 2,310.4 | 2,244.9 |
| Depreciation, amortization and accretion expenses | 1,282.7 | 1,148.9 | 1,061.7 |
| Net gains attributable to asset sales and insurance recoveries | (102.1) | (83.4) | (17.6) |
| Non-cash asset impairment charges | 34.0 | 92.6 | 63.4 |
| Total operating costs and expenses | 44,220.5 | 44,238.7 | 39,367.9 |
| General and administrative costs | 214.5 | 188.3 | 170.3 |
| Total costs and expenses | 44,435.0 | 44,427.0 | 39,538.2 |
| Equity in income of unconsolidated affiliates | 259.5 | 167.3 | 64.3 |
| Operating income | 3,775.7 | 3,467.3 | 3,109.2 |
| Interest expense | (921.0) | (802.5) | (771.8) |
| Other, net | 1.9 | (0.2) | 73.4 |
| Benefit from (provision for) income taxes | (23.1) | (57.5) | 17.2 |
| Net income | 2,833.5 | 2,607.1 | 2,428.0 |
| Net income attributable to noncontrolling interests | (46.1) | (10.2) | (8.1) |
| Net income attributable to limited partners | $2,787.4 | $2,596.9 | $2,419.9 |

Consolidated Revenues

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

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2014 | 2013 | 2012 |
| NGL Pipelines & Services: | | | |
| Sales of NGLs and related products | $15,460.1 | $15,916.0 | $14,218.5 |
| Midstream services | 1,629.7 | 1,204.2 | 949.9 |
| Total | 17,089.8 | 17,120.2 | 15,168.4 |
| Onshore Natural Gas Pipelines & Services: | | | |
| Sales of natural gas | 3,181.7 | 2,571.6 | 2,395.4 |
| Midstream services | 1,022.1 | 966.9 | 957.2 |
| Total | 4,203.8 | 3,538.5 | 3,352.6 |
| Onshore Crude Oil Pipelines & Services: | | | |
| Sales of crude oil | 19,783.9 | 20,371.3 | 17,548.7 |

| | | | |
|---|---|---|---|
| Midstream services | 400.4 | 279.1 | 113.0 |
| Total | 20,184.3 | 20,650.4 | 17,661.7 |
| Offshore Pipelines & Services: | | | |
| Sales of natural gas | 0.3 | 0.5 | 0.4 |
| Sales of crude oil | 8.6 | 5.7 | 3.3 |
| Midstream services | 147.9 | 153.2 | 187.8 |
| Total | 156.8 | 159.4 | 191.5 |
| Petrochemical & Refined Products Services: | | | |
| Sales of petrochemicals and refined products | 5,575.5 | 5,568.8 | 5,470.9 |
| Midstream services | 741.0 | 689.7 | 738.0 |
| Total | 6,316.5 | 6,258.5 | 6,208.9 |
| Total consolidated revenues | $47,951.2 | $47,727.0 | $42,583.1 |

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Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2014 was Shell Oil Company and its affiliates ("Shell"), which accounted for $4.05 billion, or 8.5%, of our consolidated revenues for the year. The following table presents our consolidated revenues from Shell by business segment for the year ended December 31, 2014 (dollars in millions):

| | |
|---|---|
| NGL Pipelines & Services | $615.5 |
| Onshore Natural Gas Pipelines & Services | 130.3 |
| Onshore Crude Oil Pipelines & Services | 3,106.0 |
| Offshore Pipelines & Services | 6.7 |
| Petrochemical & Refined Products Services | 194.2 |
| Total | $4,052.7 |

BP p.l.c. and its affiliates was our largest non-affiliated customer for 2013 and 2012, accounting for 9.0% and 9.5%, respectively, of our consolidated revenues.

Selected Energy Commodity Price Data

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

| Natural Gas, $/MMBtu (1) | Ethane, $/gallon (2) | Propane, $/gallon (2) | Normal Butane, $/gallon (2) | Isobutane, $/gallon | Natural Gasoline, $/gallon | Polymer Grade Propylene, $/pound | Refinery Grade Propylene, $/pound | WTI Crude Oil, $/barrel | LLS Crude Oil, $/barrel |
|---|---|---|---|---|---|---|---|---|---|