METRO-GOLDWYN-MAYER INC
Form SC TO-I
December 04, 2003

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

SCHEDULE TO

Tender Offer Statement Under Section 14(d)(1) Or 13(e)(1) Of The Securities Exchange Act Of 1934

METRO-GOLDWYN-MAYER INC.

(Name of Subject Company (Issuer))

METRO-GOLDWYN-MAYER INC.

(Name of Filing Persons (Offeror))

COMMON STOCK, PAR VALUE $0.01 PER SHARE

(Title of Class of Securities)

591610100

(CUSIP Number of Class of Securities)

Jay Rakow, Esq.

Senior Executive Vice President and General Counsel

Metro-Goldwyn-Mayer Inc.

10250 Constellation Boulevard

Los Angeles, CA 90067

(310) 449-3000

(Name, Address and Telephone Number of Person Authorized to Receive Notices and Communications on Behalf of the Bidder)

Copy to:

Janet S. McCloud, Esq.

Christensen, Miller, Fink, Jacobs, Glaser, Weil & Shapiro, LLP
10250 Constellation Boulevard, 19th floor

Los Angeles, CA 90067

(310) 553-3000

Charles M. Nathan, Esq.

Latham & Watkins LLP

885 Third Avenue

New York, New York 10022-4864

(212) 906-1200

CALCULATION OF FILING FEE

Transaction Valuation*	Amount of Filing Fee**
$180,000,000	$14,562

* Estimated for purposes of calculating the amount of the filing fee only, this amount is based on the purchase of 10,000,000 shares of common stock at the maximum tender offer price of $18.00 per share.

** The amount of the filing fee, calculated in accordance with Rule 0-11 of the Securities Exchange Act of 1934, as amended, and Fee Advisory #6 for Fiscal Year 2004 issued by the Securities and Exchange Commission on November 24, 2003, equals $80.90 per million of the aggregate amount of the cash offered by Metro-Goldwyn-Mayer Inc.

¨ Check the box if any part of the filing fee is offset as provided by Rule 0-11(a)(2) and identify the filing with which the offsetting fee was previously paid. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

Amount Previously Paid:	Filing Party:
Form or Registration No.:	Date Filed:

¨ Check the box if the filing relates solely to preliminary communications made before the commencement of a tender offer.

Check the appropriate boxes below to designate any transaction to which the statement relates:

¨ third-party tender offer subject to Rule 14d-1.
x issuer tender offer subject to Rule 13e-4.
¨ going-private transaction subject to Rule 13e-3.
¨ amendment to Schedule 13D under Rule 13d-2.

Check the following box if the filing is a final amendment reporting the results of the tender offer: ¨

This Tender Offer Statement on Schedule TO is intended to satisfy the reporting requirements of Rule 13e-4(c)(2) of the Securities Exchange Act of 1934, as amended.

Item 1. Summary Term Sheet.

The information set forth under Summary Term Sheet in the Offer to Purchase dated December 4, 2003 (the Offer to Purchase), attached hereto as Exhibit (a)(1)(A), is incorporated herein by reference.

Item 2. Subject Company Information.

The name of the issuer is Metro-Goldwyn-Mayer Inc., a Delaware corporation (the Company), and the address of its principal executive office is 10250 Constellation Boulevard, Los Angeles, California 90067. The Company s telephone number is (310) 449-3000.

This Tender Offer Statement on Schedule TO relates to the offer by the Company to purchase shares of its common stock, $0.01 par value per share. The Company is offering to purchase up to 10,000,000 shares, or such lesser number of shares as are properly tendered and not properly withdrawn, at a price not greater than $18.00 nor less than $16.25 per share, net to the seller in cash, without interest. The Company s offer is being made upon the terms and subject to the conditions set forth in the Offer to Purchase and in the related Letter of Transmittal, which, together with the Offer to Purchase, as amended or supplemented from time to time, constitute the offer.

The information set forth in the Offer to Purchase under Summary Term Sheet, Introduction, Section 1 (Number of Shares; Proration) and Section 8 (Price Range of the Shares; Dividends) is incorporated herein by reference.

Item 3. Identity and Background of Filing Person.

The Company is also the filing person. The Company s address and telephone number are set forth in Item 2 above. The information set forth in the Offer to Purchase under Section 11 (Interest of Directors and Executive Officers; Transactions and Arrangements Concerning the Shares) is incorporated herein by reference.

Item 4. Terms of the Transaction.

The following sections of the Offer to Purchase contain a description of the material terms of the transaction and are incorporated herein by reference:

Summary Term Sheet ;

Introduction ;

Section 1 (Number of Shares; Proration);

Section 3 (Procedures for Tendering Shares);

Section 4 (Withdrawal Rights);

Section 5 (Purchase of Shares and Payment of Purchase Price);

Section 6 (Conditional Tender of Shares);

Section 7 (Conditions of the Tender Offer);

Section 8 (Price Range of the Shares; Dividends);

Section 9 (Source and Amount of Funds);

Section 13 (Legal Matters; Regulatory Approvals);

Section 14 (United States Federal Income Tax Consequences); and

Section 15 (Extension of the Tender Offer; Termination; Amendment).

The Company s directors and executive officers have advised the Company that they do not intend to tender any of their shares in this offer.

Item 5. Past Contracts, Transactions, Negotiations and Agreements.

The information set forth in the Offer to Purchase under Section 11 (Interest of Directors and Executive Officers; Transactions and Arrangements Concerning the Shares) is incorporated herein by reference.

Item 6. Purposes of the Transaction and Plans or Proposals.

The information set forth in the Offer to Purchase under Section 2 (Purpose of the Tender Offer; Certain Effects of the Tender Offer) is incorporated herein by reference.

Item 7. Source and Amount of Funds or Other Consideration.

The information set forth in the Offer to Purchase under Section 9 (Source and Amount of Funds) is incorporated herein by reference.

Item 8. Interest in Securities of the Subject Company.

The information set forth in the Offer to Purchase under Section 11 (Interest of Directors and Executive Officers; Transactions and Arrangements Concerning the Shares) is incorporated herein by reference.

Item 9. Persons/Assets, Retained, Employed, Compensated or Used.

The information under Section 16 (Fees and Expenses) and Section 17 (Miscellaneous) is incorporated herein by reference.

Item 10. Financial Statements.

Not Applicable.

Item 11. Additional Information.

The information set forth in the Offer to Purchase under Section 11 (Interest of Directors and Executive Officers; Transactions and Arrangements Concerning the Shares), Section 9 (Source and Amount of Funds) and Section 13 (Legal Matters; Regulatory Approvals) is incorporated herein by reference. To the knowledge of the Company, no material legal proceedings relating to the tender offer are pending.

Item 12. Exhibits.

Exhibit No.	Description
(a)(1)(A)	Offer to Purchase dated December 4, 2003.
(a)(1)(B)	Letter of Transmittal.
(a)(1)(C)	Notice of Guaranteed Delivery.

Exhibit No.	Description
(a)(1)(D)	Letter to Brokers, Dealers, Commercial Banks, Trust Companies and Other Nominees dated December 4, 2003.
(a)(2)	Not Applicable.
(a)(3)	Not Applicable.
(a)(4)	Not Applicable.
(a)(5)(A)	Letter to Clients for use by Brokers, Dealers, Commercial Banks, Trust Companies and Other Nominees dated December 4, 2003.
(a)(5)(B)	Guidelines for Certification of Taxpayer Identification Number on Substitute Form W-9.
(a)(5)(C)	Press Release dated December 4, 2003.
(a)(5)(D)	Letter to Shareholders from the Chief Executive Officer of the Company, dated December 4, 2003.
(a)(5)(E)	Form of Election for Participants in the Company Stock Fund under the MGM Savings Plan.
(b)(1)	Third Amended and Restated Credit Agreement, dated as of June 11, 2002, among Metro-Goldwyn-Mayer Studios Inc., Orion Pictures Corporation, Bank of America, N.A., as administrative agent, certain lenders and certain L/C issuers, filed as an exhibit to the Company s Form 10-Q for the quarter ended June 30, 2002 (SEC File No. 001-13481).
(d)(1)	Form of Amended and Restated Shareholders Agreement dated as of August 4, 1997, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-35411).
(d)(2)	Employment Agreement of Alex Yemenidjian dated as of April 28, 1999, filed as an exhibit to the Company s Registration Statement on Form S-3 (SEC File No. 333-82775).
(d)(3)	Amendment to Employment Agreement of Alex Yemenidjian dated March 25, 2002, filed as an exhibit to the Company s Form 10-Q for the quarter ended March 31, 2002 (SEC File No. 001-13481).
(d)(4)	Employment Agreement of Christopher J. McGurk dated as of April 28, 1999, filed as an exhibit to the Company s Registration Statement on Form S-3 (SEC File No. 333-82775).
(d)(5)	Letter Agreement between the Company and Christopher J. McGurk dated April 28, 1999, filed as an exhibit to the Company s Registration Statement on Form S-3 (SEC File No. 333-82775).
(d)(6)	Amendment to Employment Agreement of Christopher J. McGurk dated March 25, 2002, filed as an exhibit to the Company s Form 10-Q for the quarter ended March 31, 2002 (SEC File No. 001-13481).
(d)(7)	Employment Agreement of William A. Jones dated as of October 10, 1996, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-35411).
(d)(8)	Amendment to Employment Agreement of William A. Jones dated as of July 16, 1999, filed as an exhibit to the Company s Form 10-K for the fiscal year ended December 31, 2000 (SEC File No. 001-13481).
(d)(9)	Employment Agreement of William A. Jones dated as of October 10, 2003.
(d)(10)	Employment Agreement of Jay Rakow dated as of August 7, 2000, filed as an exhibit to the Company s Form 10-Q for the quarter ended September 30, 2000 (SEC File No. 001-13481).
(d)(11)	Addendum to Employment Agreement of Jay Rakow dated as of August 7, 2000, filed as an exhibit to the Company s Form 10-Q for the quarter ended September 30, 2000 (SEC File No. 001-13481).

Exhibit No.	Description
(d)(12)	Employment Agreement of Jay Rakow dated as of March 15, 2003, filed as an exhibit to the Company s Form 10-Q for the quarter ended March 31, 2003 (SEC File No. 001-13481).
(d)(13)	Employment Agreement of Daniel J. Taylor dated as of August 1, 1997, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-60723).
(d)(14)	Amendment to Employment Agreement of Daniel J. Taylor dated as of June 15, 1998, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-60723).
(d)(15)	Amendment to Employment Agreement of Daniel J. Taylor dated as of November 1, 2000, filed as an exhibit to the Company s Form 10-K for the fiscal year ended December 31, 2000 (SEC File No. 001-13481).
(d)(16)	Employment Agreement of Daniel J. Taylor dated as of March 15, 2003, filed as an exhibit to the Company s Form 10-Q for the quarter ended March 31, 2003 (SEC File No. 001-13481).
(d)(17)	1998 Non-Employee Director Stock Plan, filed as an exhibit to the Company s Form S-8 (File No. 333-52953).
(d)(18)	Amended and Restated 1996 Stock Incentive Plan dated as of November 11, 1997 and form of related Stock Option Agreement, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-35411).
(d)(19)	Amendment No. 1 to Amended and Restated 1996 Stock Incentive Plan, filed as an exhibit to the Company s Registration on Form S-8 (File No. 333-83823).
(d)(20)	Form of Director Stock Option Agreement Pursuant to the Amended and Restated 1996 Stock Incentive Plan, filed as an exhibit to the Company s Form 10-Q for the quarter ended June 30, 2001 (File No. 001-13481).
(d)(21)	Senior Management Bonus Plan dated as of November 11, 1997 and form of related Bonus Interest Agreement, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (File No. 333-35411).
(d)(22)	Bonus Interest Amendment, filed as an exhibit to the Company s Form 10-K for the fiscal year ended December 31, 1998 (File No. 001-13481).
(d)(23)	Form of 2000 Employee Incentive Plan, filed as an appendix to the Company s Proxy Statement for the annual meeting held on May 4, 2000.
(d)(24)	Bonus Payment Agreement dated as of October 23, 2001, entered into by the Company, Metro-Goldwyn-Mayer Studios Inc., a Delaware corporation, and William A. Jones, filed as an exhibit to the Company s Form 10-K/A (Amendment No. 1) for the fiscal year ended December 31, 2001 (File No. 001-13481).
(d)(25)	Bonus Payment Agreement dated as of November 21, 2001, entered into by Frank G. Mancuso and Metro-Goldwyn-Mayer Studios Inc., a Delaware corporation, filed as an exhibit to the Company s Form 10-K/A (Amendment No. 1) for the fiscal year ended December 31, 2001 (File No. 001-13481).
(g)	Not Applicable.
(h)	Not Applicable.

Item 13. Information Required by Schedule 13E-3.

Not Applicable.

SIGNATURE

After due inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

METRO-GOLDWYN-MAYER INC.

By: /s/ WILLIAM A. JONES

Name: William A. Jones

Title: Senior Executive Vice President and Secretary

Dated: December 4, 2003

6

EXHIBIT INDEX

Exhibit No.	Description
(a)(1)(A)	Offer to Purchase dated December 4, 2003.
(a)(1)(B)	Letter of Transmittal.
(a)(1)(C)	Notice of Guaranteed Delivery.
(a)(1)(D)	Letter to Brokers, Dealers, Commercial Banks, Trust Companies and Other Nominees dated December 4, 2003.
(a)(2)	Not Applicable.
(a)(3)	Not Applicable.
(a)(4)	Not Applicable.
(a)(5)(A)	Letter to Clients for use by Brokers, Dealers, Commercial Banks, Trust Companies and Other Nominees dated December 4, 2003.
(a)(5)(B)	Guidelines for Certification of Taxpayer Identification Number on Substitute Form W-9.
(a)(5)(C)	Press Release dated December 4, 2003.
(a)(5)(D)	Letter to Shareholders from the Chief Executive Officer of the Company, dated December 4, 2003.
(a)(5)(E)	Form of Election for participants in the Company Stock Fund under the MGM Savings Plan.
(b)(1)	Third Amended and Restated Credit Agreement, dated as of June 11, 2002, among Metro-Goldwyn-Mayer Studios Inc., Orion Pictures Corporation, Bank of America, N.A., as administrative agent, certain lenders and certain L/C issuers, filed as an exhibit to the Company s Form 10-Q for the quarter ended June 30, 2002 (SEC File No. 001-13481).
(d)(1)	Form of Amended and Restated Shareholders Agreement dated as of August 4, 1997, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-35411).
(d)(2)	Employment Agreement of Alex Yemenidjian dated as of April 28, 1999, filed as an exhibit to the Company s Registration Statement on Form S-3 (SEC File No. 333-82775).
(d)(3)	Amendment to Employment Agreement of Alex Yemenidjian dated March 25, 2002, filed as an exhibit to the Company s Form 10-Q for the quarter ended March 31, 2002 (SEC File No. 001-13481).
(d)(4)	Employment Agreement of Christopher J. McGurk dated as of April 28, 1999, filed as an exhibit to the Company s Registration Statement on Form S-3 (SEC File No. 333-82775).
(d)(5)	Letter Agreement between the Company and Christopher J. McGurk dated April 28, 1999, filed as an exhibit to the Company s Registration Statement on Form S-3 (SEC File No. 333-82775).
(d)(6)	Amendment to Employment Agreement of Christopher J. McGurk dated March 25, 2002, filed as an exhibit to the Company s Form 10-Q for the quarter ended March 31, 2002 (SEC File No. 001-13481).
(d)(7)	Employment Agreement of William A. Jones dated as of October 10, 1996, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-35411).
(d)(8)	Amendment to Employment Agreement of William A. Jones dated as of July 16, 1999, filed as an exhibit to the Company s Form 10-K for the fiscal year ended December 31, 2000 (SEC File No. 001-13481).
(d)(9)	Employment Agreement of William A. Jones dated as of October 10, 2003.

Exhibit No.	Description
(d)(10)	Employment Agreement of Jay Rakow dated as of August 7, 2000, filed as an exhibit to the Company s Form 10-Q for the quarter ended September 30, 2000 (SEC File No. 001-13481).
(d)(11)	Addendum to Employment Agreement of Jay Rakow dated as of August 7, 2000, filed as an exhibit to the Company s Form 10-Q for the quarter ended September 30, 2000 (SEC File No. 001-13481).
(d)(12)	Employment Agreement of Jay Rakow dated as of March 15, 2003, filed as an exhibit to the Company s Form 10-Q for the quarter ended March 31, 2003 (SEC File No. 001-13481).
(d)(13)	Employment Agreement of Daniel J. Taylor dated as of August 1, 1997, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-60723).
(d)(14)	Amendment to Employment Agreement of Daniel J. Taylor dated as of June 15, 1998, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-60723).
(d)(15)	Amendment to Employment Agreement of Daniel J. Taylor dated as of November 1, 2000, filed as an exhibit to the Company s Form 10-K for the fiscal year ended December 31, 2000 (SEC File No. 001-13481).
(d)(16)	Employment Agreement of Daniel J. Taylor dated as of March 15, 2003, filed as an exhibit to the Company s Form 10-Q for the quarter ended March 31, 2003 (SEC File No. 001-13481).
(d)(17)	1998 Non-Employee Director Stock Plan, filed as an exhibit to the Company s Form S-8 (File No. 333-52953).
(d)(18)	Amended and Restated 1996 Stock Incentive Plan dated as of November 11, 1997 and form of related Stock Option Agreement, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (SEC File No. 333-35411).
(d)(19)	Amendment No. 1 to Amended and Restated 1996 Stock Incentive Plan, filed as an exhibit to the Company s Registration on Form S-8 (File No. 333-83823).
(d)(20)	Form of Director Stock Option Agreement Pursuant to the Amended and Restated 1996 Stock Incentive Plan, filed as an exhibit to the Company s Form 10-Q for the quarter ended June 30, 2001 (File No. 001-13481).
(d)(21)	Senior Management Bonus Plan dated as of November 11, 1997 and form of related Bonus Interest Agreement, filed as an exhibit to the Company s Registration Statement on Form S-1, as amended (File No. 333-35411).
(d)(22)	Bonus Interest Amendment, filed as an exhibit to the Company s Form 10-K for the fiscal year ended December 31, 1998 (File No. 001-13481).
(d)(23)	Form of 2000 Employee Incentive Plan, filed as an appendix to the Company s Proxy Statement for the annual meeting held on May 4, 2000.
(d)(24)	Bonus Payment Agreement dated as of October 23, 2001, entered into by the Company, Metro-Goldwyn-Mayer Studios Inc., a Delaware corporation, and William A. Jones, filed as an exhibit to the Company s Form 10-K/A (Amendment No. 1) for the fiscal year ended December 31, 2001 (File No. 001-13481).
(d)(25)	Bonus Payment Agreement dated as of November 21, 2001, entered into by Frank G. Mancuso and Metro-Goldwyn-Mayer Studios Inc., a Delaware corporation, filed as an exhibit to the Company s Form 10-K/A (Amendment No. 1) for the fiscal year ended December 31, 2001 (File No. 001-13481).

Exhibit No.	**Description**
(g)	Not Applicable.
(h)	Not Applicable.

9

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., federal and state regulation, the cost and availability of capital to energy companies to invest in upstream exploration and production activities and the credit quality of our customers. 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, Items 1 and 2 discussion.

For management’s discussion and analysis of our results of operations, liquidity and capital resources and capital investment program, see Part II, Item 7 of this annual report.

For detailed financial information regarding our business segments, see Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

3

Table of Contents

NGL Pipelines & Services Segment

Our NGL Pipelines & Services business segment currently includes 26 natural gas processing plants and related NGL marketing activities; approximately 19,200 miles of NGL pipelines; NGL and related product storage facilities; and 16 NGL fractionators. This segment also includes our LPG and ethane export terminals and related operations.

Natural gas processing plants and related NGL marketing activities
At the core of our natural gas processing business are 26 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. The results of operations from our natural gas processing plants are primarily dependent on the difference between the revenues we earn from extracting NGLs (in terms of cash processing fees and/or the value of any retained NGLs) and the cost of natural gas and other operating costs incurred in connection with such extraction activities.

In its raw form, natural gas produced at the wellhead (especially in association with crude oil) contains varying amounts of NGLs, such as ethane and propane. Natural gas streams containing NGLs are usually not acceptable for transportation in natural gas pipelines or for commercial use as a fuel; therefore, the raw (or unprocessed) natural gas streams must be transported to a natural gas processing plant to remove the NGLs and other impurities. Once the natural gas is processed and NGLs and impurities are removed, the residue natural gas meets pipeline and commercial quality specifications. Natural gas that has a high NGL content is referred to as “rich” or “wet” natural gas, whereas natural gas from the wellhead that is relatively free of NGLs and impurities is referred to as “lean” or “dry” natural gas. Dry natural gas can be shipped on pipelines and used as fuel with little to no processing.

In general, on an energy-equivalent basis, most NGLs have greater economic value as feedstock for petrochemical and motor gasoline production than as components of a natural gas stream. Once the mixed NGLs are extracted at a natural gas processing plant, they are transported to a centralized fractionation facility for separation into purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline). Typical uses of purity NGL products include the following:

§ 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 for heating, as an engine and industrial fuel, and as a petrochemical feedstock in the production of ethylene and propylene.

§ 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, diluent in crude oil to aid in transportation, and as a petrochemical feedstock.

In our natural gas processing business, contracts 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. Our commodity-based contracts include keepwhole, margin-band, percent-of-liquids, percent-of-proceeds and contracts featuring a combination of commodity and fee-based terms. To the extent we earn all or a portion of the extracted NGLs as consideration for our processing services, we refer to such volumes as our "equity NGL production." The terms of our natural gas processing agreements typically range from month-to-month to life of the associated production lease, with intermediate terms of one to ten years being common.

Table of Contents

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, 2018, we estimate that approximately 47% of our current portfolio of natural gas processing contracts (based on natural gas inlet volumes) were entirely fee-based, with an additional 25% of this portfolio reflecting a combination of fee-based and commodity-based terms. The terms of the remaining 28% of our portfolio of natural gas processing contracts were entirely commodity-based.

The value of natural gas that is removed from the processed stream as a result of NGL extraction (i.e., the "shrinkage") and the value of natural gas that is consumed as plant fuel are significant costs 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 shrinkage. If the operating costs of a natural gas processing plant 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.

Our NGL marketing activities entail spot and term sales of NGLs that 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 for NGL marketing 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 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. 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 marketing activities utilize a fleet of approximately 800 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, Kansas, Louisiana, Minnesota, Mississippi, New York, North Carolina and Texas. These facilities service both our rail shipments and those of our customers. Our NGL marketing activities also utilize a fleet of approximately 150 tractor-trailer tank trucks that are used to transport LPG for us and on behalf of third parties. We lease and operate the majority of these trucks and trailers.

Table of Contents

The following table presents selected information regarding our natural gas processing facilities at February 1, 2019:

Plant Name	Location(s)	Production Region Served	Ownership Interest		Net Gas Processing Capacity (MMcf/d) (1)	Total Gas Processing Capacity of Plant (MMcf/d)
Meeker	Colorado	Piceance	100.0%		1,800	1,800
Pioneer (two facilities)	Wyoming	Green River	100.0%		1,400	1,400
Yoakum	Texas	Eagle Ford	100.0%		1,050	1,050
Pascagoula	Mississippi	Gulf of Mexico	100.0%		1,000	1,000
North Terrebonne	Louisiana	Gulf of Mexico	83.0%	(2)	789	950
Chaco	New Mexico	San Juan	100.0%		600	600
Orla	Texas	Delaware	100.0%		600	600
Neptune	Louisiana	Gulf of Mexico	66.0%	(2)	430	650
Sea Robin	Louisiana	Gulf of Mexico	54.1%	(2)	352	650
Thompsonville	Texas	Eagle Ford	100.0%		330	330
Shoup	Texas	Eagle Ford	100.0%		280	280
Armstrong	Texas	Eagle Ford	100.0%		250	250
Gilmore	Texas	Frio-Vicksburg	100.0%		250	250
San Martin	Texas	Eagle Ford	100.0%		200	200
South Eddy	New Mexico	Delaware	100.0%		200	200
Waha (3)	Texas	Delaware	100.0%		150	150
Delmita	Texas	Frio-Vicksburg	100.0%		145	145
Carlsbad	New Mexico	Delaware	100.0%		130	130
Panola	Texas	Cotton Valley	100.0%		125	125
Sonora	Texas	Strawn	100.0%		120	120
Shilling	Texas	Eagle Ford	100.0%		110	110
Venice	Louisiana	Gulf of Mexico	13.1%	(4)	98	750
Indian Springs	Texas	Wilcox-Woodbine	75.0%	(2)	90	120
Chaparral	New Mexico	Delaware	100.0%		45	45
Fairway	Texas	Cotton Valley	100.0%		5	5
Total					10,549	11,910

(1) The approximate net gas processing capacity does not necessarily correspond to our ownership interest in each facility. The capacity 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) Prior to March 2018, our ownership in the Waha plant was held through our 50% equity investment in Delaware Basin Gas Processing LLC ("Delaware Processing"). We acquired the remaining 50% equity interest in Delaware Processing in March 2018 for $150.6 million in cash. For information regarding this transaction, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(4) Our ownership in the Venice plant is held indirectly through our equity method investment in Venice Energy Services Company, L.L.C.

We operate all of our natural gas processing facilities except for the Venice plant. On a weighted-average basis, utilization rates for our natural gas processing plants were approximately 52.7%, 51.8% and 50.8% for the years ended

December 31, 2018, 2017 and 2016, respectively.

Orla natural gas processing facility. In June 2016, we announced plans to construct a cryogenic natural gas processing plant and related natural gas gathering lines near Orla, Texas in Reeves County. The Orla facility is designed to support the continued growth in NGL-rich natural gas production from the Delaware Basin and is supported by long-term customer commitments. We own and operate the Orla facility.

6

Table of Contents

The Orla facility will be completed in three stages. The first processing train ("Orla I"), which commenced operations in May 2018, has a natural gas processing capacity of 300 MMcf/d and the capability to extract more than 40 MBPD of mixed NGLs. In conjunction with the start-up of Orla I, we placed into service approximately 70 miles of residue natural gas pipelines that connect Orla to our Texas Intrastate System. We also placed into service a 30-mile extension of our NGL system that provides customers at Orla with NGL takeaway capacity and direct access to our integrated network of downstream NGL assets. A second processing train ("Orla II"), which commenced operations in October 2018, added 300 MMcf/d of incremental processing capacity to the Orla facility and increased the overall extraction rate for mixed NGLs up to 80 MBPD. A third processing train (Orla III) is scheduled to be completed in the second quarter of 2019. Once Orla III is completed, the Orla facility will have 900 MMcf/d of total processing capacity and allow us to extract up to 120 MBPD of mixed NGLs.

Mentone natural gas processing facility. In October 2018, we announced that construction of our Mentone cryogenic natural gas processing plant had commenced. The Mentone plant, which is located in Loving County, Texas, is expected to have the capacity to process 300 MMcf/d of natural gas and extract more than 40 MBPD of NGLs. The project is scheduled to be completed in the first quarter of 2020 and is supported by a long-term acreage dedication agreement.

The Mentone plant further extends our presence in the growing Delaware Basin and provides access to our fully integrated midstream asset network. To support the development of Mentone, we are constructing approximately 70 miles of gathering and residue pipelines and expanding compression capabilities. These projects will allow the Mentone plant to link to our NGL system, including the Shin Oak NGL Pipeline which entered limited commercial service in February 2019, as well as our Texas Intrastate System. We will own and operate the Mentone facility and related infrastructure.

When the Mentone plant is completed and placed into service, we expect to have an aggregate 1.6 Bcf/d of natural gas processing capacity and 250 MBPD of NGL production from our processing plants in the Delaware Basin.

NGL pipelines

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

The results of operations from our NGL pipelines are primarily dependent upon the volume of NGLs transported (or capacity reserved) and the associated fees we charge for such transportation services. Transportation fees charged to shippers are based on either tariffs regulated by federal governmental agencies, including the Federal Energy Regulatory Commission ("FERC"), or contractual arrangements. See "Regulatory Matters" within this Part I, Items 1 and 2 for additional information regarding governmental oversight of our liquids pipelines.

Excluding certain linefill volumes and volumes shipped in connection with our marketing activities, we typically do not take title to NGLs transported by third party shippers on our pipelines; rather, the third party shipper retains title and the associated commodity price risk.

Table of Contents

The following table presents selected information regarding our NGL pipelines at February 1, 2019:

Description of Asset	Location(s)	Ownership Interest	Pipeline Length (Miles)
Mid-America Pipeline System (1)	Midwest and Western U.S.	100.0%	8,035
South Texas NGL Pipeline System	Texas	100.0%	1,917
Dixie Pipeline (1)	South and Southeastern U.S.	100.0%	1,307
ATEX (1)	Texas to Midwest and Northeast U.S.	100.0%	1,192
Chaparral NGL System (1)	Texas, New Mexico	100.0%	1,085
Louisiana Pipeline System (1)	Louisiana	100.0%	950
Seminole NGL Pipeline (1,2)	Texas	100.0%	869
Texas Express Pipeline (1)	Texas	35.0%	594
Skelly-Belvieu Pipeline (1)	Texas, Oklahoma	50.0%	572
Front Range Pipeline (1)	Colorado, Oklahoma, Texas	33.3%	447
Aegis Ethane Pipeline (1)	Texas, Louisiana	100.0%	299
Houston Ship Channel Pipeline System	Texas	100.0%	275
Rio Grande Pipeline (1)	Texas	70.0%	249
Panola Pipeline (1)	Texas	55.0%	249
Lou-Tex NGL Pipeline (1)	Texas, Louisiana	100.0%	206
Promix NGL Gathering System	Louisiana	50.0%	201
Texas Express Gathering System	Texas	45.0%	170
Tri-States NGL Pipeline (1)	Alabama, Mississippi, Louisiana	83.3%	168
Others (seven systems) (3)	Various	Various (4)	454
Total			19,239

(1) Interstate transportation services provided by these liquids pipelines, in whole or part, are regulated by federal governmental agencies.
(2) Pipeline mileage shown for the Seminole NGL Pipeline excludes 379 miles converted to crude oil service in February 2019 and used by our Midland-to-ECHO 2 Pipeline System.
(3) Includes our Belle Rose and Wilprise pipelines located in the coastal regions of Louisiana; two pipelines located near Port Arthur in southeast Texas; our San Jacinto pipeline located in East Texas; our Permian NGL lateral pipelines located in West Texas; Leveret pipeline in West Texas and New Mexico; and a pipeline in Colorado associated with our Meeker facility. Transportation services provided by the Wilprise, Permian NGL and Leveret pipelines are regulated by federal governmental agencies.
(4) 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.

The maximum number of barrels per day that our NGL pipelines can transport depends on operating rates achieved at a given point in time between various segments of each system (e.g., demand levels at each injection and 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. In the aggregate, net throughput volumes for these pipelines were 3,461 MBPD, 3,168 MBPD and 2,965 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

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

§ The Mid-America Pipeline System is an NGL pipeline system consisting of four primary segments: the 3,119-mile Rocky Mountain pipeline, the 2,138-mile Conway North pipeline, the 632-mile Ethane-Propane (“EP”) Mix pipeline, and the 2,146-mile Conway South pipeline. The Mid-America Pipeline System operates in 13 states: Colorado, Illinois, Iowa, Kansas, Minnesota, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Utah, Wisconsin and Wyoming. Volumes transported on the Mid-America Pipeline System primarily originate from natural gas processing plants located in the Rocky Mountains and Mid-Continent regions, as well as NGL fractionation and storage facilities in Kansas and Texas.

Table of Contents

The Rocky Mountain pipeline transports mixed NGLs from production fields located in 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 Mont Belvieu, Hobbs and Conway, provide buyers and sellers with a centralized location for the storage and pricing of products, while also providing connections to intrastate and/or interstate pipelines. The EP Mix segment transports EP mix from the Conway hub to petrochemical plants in Iowa and Illinois. 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 NGL 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.

§ The South Texas NGL Pipeline System is a network of NGL gathering and transportation pipelines located in South Texas that gather and transport mixed NGLs from natural gas processing plants (owned by either us or third parties) located in South Texas to our NGL fractionators in South Texas and NGL fractionation and storage complex located in and near Mont Belvieu, Texas. The Mont Belvieu area in Chambers County, Texas, with its significant energy-related infrastructure, is a key hub of the global NGL industry (the "Mont Belvieu hub"). 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 other NGL pipelines and to our Mont Belvieu storage complex. The South Texas NGL Pipeline System is a component of our ethane header system, extending it from the Mont Belvieu hub to Corpus Christi, Texas.

§ The Dixie Pipeline transports propane and other NGLs and extends from southeast Texas to markets in the southeastern U.S. Propane supplies transported on this system primarily originate from southeast Texas, south Louisiana and Mississippi. The Dixie Pipeline 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 ATEX, or Appalachia-to-Texas Express, pipeline transports ethane in southbound service from third-party owned 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 operates in nine states: Arkansas, Illinois, Indiana, Louisiana, Missouri, Ohio, Pennsylvania, Texas and West Virginia.

§ The Chaparral NGL System transports mixed NGLs from natural gas processing plants located in West Texas and New Mexico to Mont Belvieu. This system consists of the 906-mile Chaparral pipeline and the 179-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.

§ The Seminole NGL Pipeline transports NGLs from the Hobbs hub and the Permian Basin to markets in southeast Texas, including our NGL fractionation complex located in and near Mont Belvieu. NGLs originating on the Mid-America Pipeline System are a significant source of throughput for the Seminole NGL Pipeline.

Historically, the Seminole NGL Pipeline system was comprised of two parallel pipelines extending to Mont Belvieu. In January 2019, we completed the conversion of a portion of one of these pipelines from NGL service to crude oil service. The conversion does not reduce our NGL transportation capacity since displaced NGLs are transported using our other NGL pipelines, including our Shin Oak NGL Pipeline. Furthermore, we have the ability to convert this pipeline back to NGL service should market and physical takeaway conditions warrant. See "Crude Oil Pipelines & Services Segment – Crude Oil Pipelines" within this Items 1 and 2 section for additional information regarding the Midland-to-ECHO 2 Pipeline System.

9

Table of Contents

- The Texas Express Pipeline extends from Skellytown, Texas to our NGL fractionation and storage complex located in and near Mont Belvieu. Mixed NGLs from production fields located in 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. In addition, the Texas Express Pipeline transports mixed NGLs gathered by the Texas Express Gathering System. Also, mixed NGLs originating from the Denver-Julesburg ("DJ") Basin in Colorado are transported to the Texas Express Pipeline using the Front Range Pipeline. Our 35% ownership interest in the Texas Express Pipeline is held indirectly through our equity method investment in Texas Express Pipeline LLC.

In May 2018, we conducted open commitment periods to determine shipper interest in expansions of the Texas Express Pipeline and Front Range Pipeline. Given the positive responses we received from shippers, we are proceeding with the expansions, which are expected to increase the transportation capacity of Texas Express Pipeline and Front Range Pipeline by 90 MBPD and 100 MBPD, respectively. The expansions are designed to facilitate growing production of NGLs from domestic shale basins, including the DJ Basin, by providing producers with flow assurance and greater access to Gulf Coast markets. We anticipate the expansion projects will be placed into service during the third quarter of 2019.

- The Skelly-Belvieu Pipeline transports mixed NGLs from Skellytown, Texas to Mont Belvieu. The Skelly-Belvieu Pipeline receives a significant quantity of NGLs through an interconnect with our Mid-America Pipeline System at Skellytown. Our 50% ownership interest in the Skelly-Belvieu Pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C.

- The Front Range Pipeline transports mixed NGLs from natural gas processing plants located in the DJ Basin in Colorado to an interconnect with our Texas Express Pipeline, Mid-America Pipeline System and other third party facilities located at Skellytown, Texas. Our 33.3% ownership interest in the Front Range Pipeline is held indirectly through our equity method investment in Front Range Pipeline LLC. As previously mentioned, we are in the process of expanding the transportation capacity of the Front Range Pipeline by 100 MBPD.

- The Aegis Ethane Pipeline ("Aegis") delivers purity ethane to petrochemical facilities located along the southeast Texas and Louisiana Gulf Coast. Aegis, when combined with a portion of our South Texas NGL Pipeline System, forms an ethane header system stretching from Corpus Christi, Texas to the Mississippi River in Louisiana.

- The Houston Ship Channel Pipeline System connects our Mont Belvieu area assets to our marine terminals on the Houston Ship Channel and to area petrochemical plants, refineries and other pipelines.

- The Rio Grande Pipeline transports mixed NGLs from near Odessa, Texas to a pipeline interconnect at the Mexican border south of El Paso, Texas. We own a 70% consolidated interest in the Rio Grande Pipeline through our majority owned subsidiary, Rio Grande Pipeline Company.

- The Panola Pipeline transports mixed NGLs from injection points near Carthage, Texas to the Mont Belvieu hub and supports the Haynesville and Cotton Valley oil and gas production areas. We own a 55% consolidated interest in the Panola Pipeline through our majority owned subsidiary, Panola Pipeline Company, LLC.

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

- The Promix NGL Gathering System gathers mixed NGLs from natural gas processing plants in southern Louisiana for delivery to our Promix NGL fractionator. Our 50% 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").

§ The Texas Express Gathering System is comprised of two gathering systems, Elk City and North Texas, that deliver mixed NGLs to the Texas Express Pipeline. Our 45% ownership interest in the Texas Express Gathering System is held indirectly through our equity method investment in Texas Express Gathering LLC.

10

Table of Contents

- The Tri-States NGL Pipeline transports mixed NGLs from Mobile Bay, Alabama to points near Kenner, Louisiana. 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.

Shin Oak NGL Pipeline. In April 2017, we announced plans to build the 658-mile Shin Oak NGL Pipeline to transport growing NGL production from the Permian Basin to our NGL fractionation and storage complex located at the Mont Belvieu hub. In February 2019, the 24-inch diameter mainline segment from Orla, Texas to Mont Belvieu was placed into limited commercial service with an initial transportation capacity of 250 MBPD. Completion of the related 20-inch diameter Waha lateral is scheduled for the second quarter of 2019. Supported by long-term customer commitments, the Shin Oak NGL Pipeline will ultimately provide up to 550 MBPD of transportation capacity, which is expected to be available in the fourth quarter of 2019.

In May 2018, Apache Corporation (“Apache”) executed a long-term supply agreement to sell all of its NGL production from the Alpine High discovery to us. Alpine High is a major hydrocarbon resource located in the Delaware Basin that encompasses rich and dry natural gas and oil-bearing horizons. Enterprise has committed to purchase up to 205 MBPD of NGLs from Apache over the initial ten-year term of the supply agreement, the term of which may be extended at the consent of the parties.

In conjunction with the long-term NGL supply agreement, we granted Apache an option to acquire up to a 33% equity interest in our subsidiary that owns the Shin Oak NGL Pipeline. In November 2018, Apache contributed this option to Altus Midstream Company, which is a majority-owned subsidiary of Apache. The option is exercisable within sixty days after certain completion milestones are met (as defined in the underlying agreements), which we expect to occur in the second quarter of 2019.

NGL fractionation

We own or have interests in 16 NGL fractionators located in Texas and Louisiana that separate mixed NGL streams into purity NGL products for third party customers and also our NGL marketing activities. Mixed NGLs extracted by domestic natural gas processing plants represent the largest source of volumes processed by our NGL fractionators. Based upon industry data, we believe that sufficient volumes of mixed NGLs, especially those originating from natural gas processing plants located in West Texas, 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.

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.

Table of Contents

The following table presents selected information regarding our NGL fractionation facilities at February 1, 2019:

Description of Asset	Location	Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu complex:				
Fracs I, II and III	Texas	75.0% (2)	189	245
Fracs IV, V, VI and IX	Texas	100.0%	345	345
Fracs VII and VIII	Texas	75.0% (3)	128	170
Total Mont Belvieu complex			662	760
Shoup and Armstrong	Texas	100.0%	93	93
Hobbs	Texas	100.0%	75	75
Norco	Louisiana	100.0%	75	75
Promix	Louisiana	50.0%	73	145
Tebone	Louisiana	100.0%	30	30
Baton Rouge	Louisiana	32.2%	19	60
Total			1,027	1,238

(1) The approximate net plant capacity does not necessarily correspond to our ownership interest in each facility. The capacity 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 a 75% undivided interest in these fractionators.
(3) We own a 75% consolidated equity interest in NGL fractionators VII and VIII through our majority owned subsidiary, Enterprise EF78 LLC.

On a weighted-average basis, overall utilization rates for our NGL fractionators were 94.0%, 91.0% and 90.2% during the years ended December 31, 2018, 2017 and 2016, respectively.

The following information describes our NGL fractionators, all of which we operate.

§ The Mont Belvieu NGL fractionation complex includes fractionators located either in Mont Belvieu or in surrounding areas of Chambers County, Texas. This complex processes mixed NGLs from several major NGL supply basins in North America, including the Permian Basin, Rocky Mountains, Eagle Ford Shale, Mid-Continent and San Juan Basin. In addition, the Mont Belvieu NGL fractionation complex features connectivity to our network of NGL supply and distribution pipelines, approximately 130 MMBbls of underground salt dome storage capacity, along with access to international markets through our marine terminals located on the Houston Ship Channel.

Demand for NGL fractionation capacity continues to expand as producers in domestic shale plays such as the Permian Basin, Eagle Ford Shale and DJ Basin seek market access and end users require supply assurance. In May 2018, we placed our ninth NGL fractionator, which is located in Chambers County, Texas, into service. The new fractionator has a capacity of 90 MBPD, which increased total NGL fractionation capacity at our Mont Belvieu complex to 760 MBPD. In addition, we announced in November 2018 plans to construct a new NGL fractionation facility in Chambers County, Texas adjacent to our existing Mont Belvieu NGL fractionation complex. The new facility will consist of two fractionation trains capable of processing a combined 300 MBPD of NGLs. The first of the two fractionation trains will have a nameplate capacity of 150 MBPD and is scheduled to be completed and begin service in the fourth quarter of 2019. The second of these fractionation trains will also have a nameplate capacity of 150

MBPD, and is scheduled to begin service in the first half of 2020.

§ The Shoup and Armstrong NGL fractionators in South Texas process mixed NGLs supplied by regional 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 the Mont Belvieu hub using our South Texas NGL Pipeline System.

In November 2018, we announced a project to optimize our Shoup NGL fractionator by expanding and repurposing a portion of our South Texas pipelines. The project will entail the construction of approximately 21 miles of new pipeline along with the conversion of approximately 65 miles of existing natural gas pipelines to NGL service, which will allow us to supply Shoup with an additional 25 MBPD of NGL volumes. The expanded pipeline capacity is expected to be available in the third quarter of 2019.

12

Table of Contents

§ The Hobbs NGL fractionator serves NGL producers in West Texas, New Mexico and Colorado. This 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 NGL Pipeline, thus providing customers access to both the Mont Belvieu and Conway hubs.

§ The Norco NGL fractionator receives mixed NGLs 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 plants.

§ The Promix NGL fractionator receives mixed NGLs from natural gas processing plants located in south Louisiana and along the Mississippi Gulf Coast, including our Neptune and Pascagoula plants. The Promix NGL fractionation facility includes three NGL storage caverns and a barge dock that are integral to its operations. Our 50% ownership interest in the Promix fractionator is held indirectly through our equity method investment in Promix.

§ The Tebone NGL fractionator, which was restarted in February 2019 in light of regional demand for fractionation services, receives mixed NGLs from our Louisiana natural gas processing plants, as well as our Mont Belvieu storage complex. The resumption of service at our Tebone fractionator complements our operations at the Norco and Promix NGL fractionators and provides us with another processing option for mixed NGLs delivered to Mont Belvieu.

§ The Baton Rouge NGL fractionator receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and south Louisiana. This facility includes a leased NGL storage cavern. Our 32.2% ownership interest in the Baton Rouge fractionator is held indirectly through our equity method investment in Baton Rouge Fractionators LLC.

NGL and related product storage facilities

We utilize underground salt dome storage caverns and above-ground storage tanks to store mixed and purity NGLs, petrochemicals and related products that are owned by us and our customers. The results of operations from our storage facilities 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 associated fees we charge.

The following table presents selected information regarding our NGL and related product storage assets at February 1, 2019:

Storage Capacity by Asset	Location	Ownership Interest	Net Usable Storage Capacity (MMBbls) (1)
Mont Belvieu storage complex	Texas	100.0%	129.8
Almeda and Markham (2)	Texas	Leased	12.4
Breaux Bridge, Anse La Butte and Sorrento (3)	Louisiana	100.0%	12.7
Petal (4)	Mississippi	100.0%	5.1
Hutchinson (5)	Kansas	100.0%	4.0
Others (6)	Various	Various	14.2
Total			178.2

(1) Net usable storage capacity is based on our ownership interest or contractual right-of-use.

(2) These storage facilities are used in connection with our South Texas NGL Pipeline System.
(3) These storage facilities are used in connection with our Louisiana Pipeline System.
(4) This storage facility is used in connection with our Dixie Pipeline.
(5) This storage facility is used in connection with our Mid-America Pipeline System.
(6) Primarily consists of operational storage capacity for our major pipeline systems, including the Mid-America Pipeline System, Dixie Pipeline and TE Products Pipeline. We own substantially all of this storage capacity.

We operate substantially all of our NGL and related product storage facilities.

13

Table of Contents

Our largest underground storage facility is located at the Mont Belvieu hub in Chambers County, Texas. This facility consists of 38 underground salt dome caverns used to store and redeliver mixed and purity NGLs, petrochemicals and related products. This facility has an aggregate usable storage capacity of 129.8 MMBbls, a brine system with approximately 31 MMBbls of above-ground brine storage capacity and five wells used in brine production.

NGL marine terminals and related operations

We own and operate marine export and import terminals for NGLs. The results of operations of these facilities, all of which are located on the Houston Ship Channel, are primarily dependent upon the level of volumes handled and the associated loading/unloading fees we charge for such services.

The following information describes our Houston Ship Channel terminals, both of which we operate.

§ The Enterprise Hydrocarbons Terminal ("EHT") is located on the Houston Ship Channel and provides terminaling services to exporters, marketers, distributors, chemical companies and major integrated oil companies. EHT has extensive waterfront access consisting of seven deep-water ship docks and one barge dock. The terminal 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 enables us to handle larger vessels than our competitors because our waterfront has fewer draft and beam (width) restrictions. The size and structure of our waterfront allows us to receive and unload products for our customers and provide terminaling and dock services.

EHT can load refrigerated cargoes of low-ethane propane and/or butane (collectively referred to as LPG) onto multiple tanker vessels simultaneously. Our LPG export services continue to benefit from increased NGL supplies produced from domestic shale plays such as the Permian Basin and Eagle Ford Shale and international demand for propane as a feedstock in ethylene production and for power generation and heating purposes. LPG loading volumes at EHT averaged 445 MBPD, 424 MBPD and 420 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

Our current loading capacity for LPG is approximately 545 MBPD. In September 2018, we announced a project to increase LPG loading capacity at EHT by 175 MBPD, or approximately 5 MMBbls per month. The expansion will bring our total LPG export capacity at EHT to 720 MBPD, or approximately 21 MMBbls per month. Upon completion of this expansion project, EHT will have the capability to load up to six Very Large Gas Carrier ("VLGC") vessels simultaneously, while maintaining the option to switch between loading propane and butane. Once operational, the expansion will allow EHT to load a single VLGC in less than 24 hours, creating greater efficiencies and cost savings for our customers. The incremental loading capacity is expected to be available in the third quarter of 2019.

The primary customer of EHT is our NGL marketing group, which uses EHT to meet the needs of export customers. NGL marketing transacts with these customers using long-term sales contracts with take-or-pay provisions and/or exchange agreements. In recent years, the U.S. has become the largest exporter of LPG in the world, with shipments originating from EHT playing a key role.

Of the LPG cargoes we loaded for export at EHT during the year ended December 31, 2018, the destination markets were as follows: 55% to Asia; 18% to North America and the Caribbean; 13% to Central and South America; 12% to Europe and Africa; and 2% to other destinations, including Australia and the Middle East. Based on available information, our LPG sales to export customers represented the following percentage of each destination market's approximate total supply: 51% for North America and the Caribbean; 43% for Asia; 34% for Central and South America; 21% for Europe and Africa; and 10% for other destinations, including Australia and the Middle East.

EHT also includes an NGL import terminal. This import terminal can offload NGLs from tanker vessels at rates up to 14,000 barrels per hour depending on the product. Our NGL import volumes for the last three years were minimal.

14

Table of Contents

EHT also provides terminaling services involving crude oil, petrochemical and refined products. EHT's assets and activities associated with crude oil terminaling and storage are classified and presented as a component of our Crude Oil Pipelines & Services business segment. EHT's activities associated with petrochemical and refined products customers are classified and described within our Petrochemical & Refined Products Services business segment.

§ The Morgan's Point Ethane Export Terminal, located on the Houston Ship Channel, has an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour of fully refrigerated ethane and is the largest of its kind in the world. The terminal supports domestic production of U.S. ethane from shale plays by providing the global petrochemical industry with access to a low-cost feedstock option and opportunities for supply diversification. We estimate that U.S. Gulf Coast ethane supply currently exceeds U.S. demand by approximately 300 MBPD and could exceed demand by approximately 1 MMBPD in 2024, after considering estimated incremental demand from third party ethylene production facilities that are being constructed along the Gulf Coast. By providing producers with access to the export market, the Morgan's Point Ethane Export Terminal supports continued development of U.S. energy reserves.

Ethane volumes handled by the terminal are sourced from our Mont Belvieu NGL fractionation and storage complex. Ethane loading volumes at the terminal averaged 146 MBPD, 90 MBPD and 15 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively. The terminal was placed into commercial service in August 2016.

Crude Oil Pipelines & Services Segment

Our Crude Oil Pipelines & Services business segment currently includes approximately 5,300 miles of crude oil pipelines, crude oil storage and marine terminals, and associated crude oil marketing activities.

Crude oil pipelines

We have crude oil gathering and transportation pipelines located in Oklahoma, New Mexico and Texas. The results of operations from providing crude oil transportation services is primarily dependent upon the volume handled (or capacity reserved) and the level of fees charged (typically on a per barrel basis). Fees charged to shippers are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. See "Regulatory Matters" within this Part I, Items 1 and 2 discussion for additional information regarding governmental oversight of our crude oil pipelines and storage facilities.

The following table presents selected information regarding our crude oil pipelines and related operations at February 1, 2019:

Description of Asset	Location(s)	Our Ownership Interest	Operational Storage Capacity (MMBbls) (2)	Pipeline Length (Miles)
Seaway Pipeline (1)	Texas, Oklahoma	50.0%	8.8	1,271
West Texas System (1)	Texas, New Mexico	100.0%	0.9	1,034
South Texas Crude Oil Pipeline System	Texas	100.0%	3.8	648
Basin Pipeline (1)	Texas, New Mexico, Oklahoma	13.0% (3)	6.0	618
EFS Midstream System	Texas	100.0%	0.3	485
Midland-to-ECHO 2 Pipeline System	Texas	100.0%	--	440
Midland-to-ECHO 1 Pipeline System	Texas	80.0%	3.9	418
Eagle Ford Crude Oil Pipeline System	Texas	50.0%	4.5	378
Total			28.2	5,292

(1) Transportation services provided by these liquids pipelines are regulated, in whole or part, by federal governmental agencies.
(2) Operational storage capacity amounts presented on a gross basis.
(3) We proportionately consolidate our 13% undivided interest in the Basin Pipeline.

In October 2018, we sold our Red River System and associated crude oil linefill for $134.9 million. For additional information regarding this sale, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Table of Contents

The maximum number of barrels per day that our crude oil pipelines can transport depends on the operating rates 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. In the aggregate, net throughput volumes for these pipelines were 2,000 MBPD, 1,820 MBPD and 1,388 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

The following information describes our principal 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. Our 50% ownership interest in the Seaway Pipeline is held indirectly through our equity method investment in Seaway Crude Pipeline Company LLC ("Seaway"). The Seaway Pipeline is comprised of the Longhaul System, the Freeport System and the Texas City System. The Cushing hub is an industry trading hub and price settlement point for West Texas Intermediate ("WTI") crude oil on the New York Mercantile Exchange ("NYMEX").

The Longhaul System consists of two approximately 500-mile, 30-inch diameter pipelines (Seaway I and the Seaway Loop) that provide north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal located near Freeport, Texas. The aggregate transportation capacity of the Longhaul System is approximately 950 MBPD, depending on the type and mix of crude oil being transported and other variables. The Jones Creek terminal is connected by pipeline to our Enterprise Crude Houston ("ECHO") storage terminal, which enables Seaway to serve a variety of customers along the upper Texas Gulf Coast including the Beaumont/Port Arthur area.

The Freeport System consists of a marine terminal that facilitates both crude oil imports and exports, along with pipelines that transport crude oil to and from Freeport, Texas and the Jones Creek terminal.

The Texas City System consists of a marine terminal and storage tanks, various pipelines and related infrastructure used to transport crude oil to refineries in the Texas City, Texas area and to and from terminals in the Galena Park, Texas area, our ECHO terminal and locations along the Houston Ship Channel. The Texas City System also receives production from certain offshore Gulf of Mexico developments. The intrastate pipeline transportation capacity of the Freeport System and Texas City System is approximately 480 MBPD and 800 MBPD, respectively. Seaway's Texas City marine terminal features two docks, a 45-foot draft, an overall length of 1,125 feet, a 200-foot beam (width) and the capacity to load crude oil at a rate of 35,000 barrels per hour.

In June 2018, our crude oil marketing group commenced the loading of Very Large Crude Carrier ("VLCC") tankers using Seaway's Texas City terminal in combination with lightering operations in the Gulf of Mexico.

§ The West Texas System connects crude oil gathering systems in West Texas and southeast New Mexico to our terminal facility located in Midland, Texas. The West Texas System, including the recently completed Loving County pipeline, is a key part of our strategic aggregation program designed to support Permian Basin producers. The Loving County pipeline, which was completed in July 2018, can currently transport 200 MBPD of crude oil and condensate from various points in New Mexico and West Texas to our Midland, Texas crude oil terminal; however, we expect to complete an expansion project in March 2019 that will increase its transportation capacity up to 350 MBPD. At Midland, shippers will have access to storage and terminal services, as well as connectivity to multiple transportation alternatives such as trucking and pipeline infrastructure that offer access to various downstream markets, including the Gulf Coast.

§ The South Texas Crude Oil Pipeline System transports crude oil and condensate originating in South Texas to customers in the Houston area. This system includes storage terminal assets located at Sealy, Texas. The South

Texas Crude Oil Pipeline System also includes our Rancho II pipeline, which extends 89-miles from the Sealy terminal to our ECHO terminal. From ECHO, we have connectivity to refinery customers and our marine terminals.

§ The Basin Pipeline transports crude oil from the Permian Basin in West Texas and southern New Mexico to the Cushing hub.

16

Table of Contents

- The EFS Midstream System serves producers in the Eagle Ford Shale, providing condensate gathering and processing services as well as gathering, treating and compression services for associated natural gas. The EFS Midstream System includes 485 miles of gathering pipelines, 11 central gathering plants having a combined condensate storage capacity of 0.3 MMBbls, 171 MBPD of condensate stabilization capacity and 1.0 Bcf/d of associated natural gas treating capacity.

- The Midland-to-ECHO 2 Pipeline System, which began limited commercial service in February 2019, provides us with approximately 200 MBPD of incremental crude oil transportation capacity from the Permian Basin to markets in the Houston area. The pipeline is expected to enter full commercial service in April 2019. The pipeline originates at our Midland terminal and extends 440 miles to our Sealy storage terminal, with volumes arriving at Sealy transported to our ECHO terminal using the Rancho II pipeline, which is a component of our South Texas Crude Oil Pipeline System.

We converted a portion of our Seminole NGL Pipeline system from NGL service to crude oil service to create the Midland-to-Sealy segment of this pipeline system. The conversion is supported by a 10.75-year transportation contract with firm demand fees. We have the ability to convert this pipeline back to NGL service should market and physical takeaway conditions warrant.

- The Midland-to-ECHO 1 Pipeline System, which became fully operational in the second quarter of 2018, provides Permian Basin producers with the ability to transport multiple grades of crude oil, including WTI, WTI light sweet crude oil ("WTI Light"), West Texas Sour, and condensate, to Gulf Coast markets. As a result of operating enhancements and supplementary infrastructure, the pipeline's transportation capacity is expected to increase to 620 MBPD beginning in March 2019.

The Midland-to-ECHO 1 Pipeline System originates at our Midland terminal and extends 418 miles to our Sealy storage terminal. Volumes arriving at Sealy are then transported to our ECHO terminal using the Rancho II pipeline. Using the ECHO terminal, shippers on the Midland-to-ECHO 1 Pipeline System have access to every refinery in Houston, Texas City, Beaumont and Port Arthur, Texas, as well as our crude oil export dock facilities. The Midland-to-ECHO 1 Pipeline System includes certain storage assets located at Sealy, Texas.

The majority of the Midland-to-ECHO 1 Pipeline System is owned by Whitethorn Pipeline Company LLC ("Whitethorn"), in which we own an 80% equity interest. In June 2018, an affiliate of Western Gas Partners, LP acquired a 20% equity interest in Whitethorn for $189.6 million in cash.

- The Eagle Ford Crude Oil Pipeline System transports crude oil and condensate for producers in South Texas. The system, which is effectively looped and has a capacity to transport over 600 MBPD of light and medium grades of crude oil, consists of 378 miles of crude oil and condensate pipelines originating in Gardendale, Texas and extending to Corpus Christi, Texas. The system interconnects with our South Texas Crude Oil Pipeline System in Wilson County, Texas and a marine terminal located in Corpus Christi that is under construction. Our 50% ownership interest in the Eagle Ford Crude Oil Pipeline System is held indirectly through our equity method investment in Eagle Ford Pipeline LLC.

Crude oil terminals

In addition to the operational storage capacity associated with our crude oil pipelines, we also own and operate crude oil terminals located in Houston, Midland and Beaumont, Texas and Cushing, Oklahoma that are used to store crude oil for us and our customers. In conjunction with other aspects of our midstream network, our crude oil terminals provide Gulf Coast refiners with an integrated system featuring supply diversification, significant storage capabilities and a high capacity pipeline distribution system that is connected to customers having an aggregate refining capacity of approximately 4.4 MMBPD.

The results of operations from crude oil terminals are primarily dependent upon the level of volumes stored and the length of time such storage occurs, including the level of firm storage capacity reserved, pumpover volumes and the fees associated with each activity. If the terminal offers marine services, the results of operations from these activities are primarily dependent upon the level of volumes handled and the associated loading/unloading fees we charge for such services.

Table of Contents

The following table presents selected information regarding our crude oil terminals at February 1, 2019:

Description of Asset	Location(s)	Ownership Interest	Number of Marine Docks	Number of Above-Ground Tanks in Service	Storage Capacity (MMBbls)
EHT (crude oil)	Texas	100.0%	7 deep-water ship; 1 barge	84	24.0
ECHO (1)	Texas	100.0%	n/a	15	6.4
Beaumont Marine West	Texas	100.0%	4 deep-water ship; 2 barge	12	4.1
Cushing	Oklahoma	100.0%	n/a	20	3.5
Midland	Texas	100.0%	n/a	12	2.5
Total				143	40.5

(1) Number of tanks and storage capacity excludes three tanks that are used in the operation of our Midland-to-ECHO 1 Pipeline System and two tanks owned by Seaway.

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

§ The EHT crude oil terminal is one of the largest such facilities on the Gulf Coast and part of our EHT complex, which is located on the Houston Ship Channel and features extensive waterfront access consisting of seven deep-water ship docks and a barge dock. As noted previously, the terminal 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.

§ The ECHO terminal is located in Houston, Texas and provides storage customers with access to major refineries located in the Houston, Texas City and Beaumont/Port Arthur areas. ECHO also has connections to marine terminals, including EHT, that provide access to any refinery on the U.S. Gulf Coast and international markets.

In September 2018, the CME Group, a leading derivatives marketplace, announced that suppliers, refiners and end users of U.S. crude oil have a new way to price and hedge WTI in Houston, Texas. Participants will have the flexibility to make or take delivery of WTI at our ECHO terminal, EHT or pipeline interconnect at Genoa Junction. The new futures contracts received regulatory approval in October 2018 and are listed with and subject to the rules of the NYMEX, beginning with the January 2019 contract month.

§ The Beaumont Marine West terminal is located on the Neches River near Beaumont, Texas. This terminal includes four deep-water docks and two barge docks that facilitate the exporting and importing of crude oil and related products.

§ The Cushing terminal is located at the Cushing hub in Oklahoma and provides crude oil storage, pumpover and trade documentation services. This terminal is one of the origination points for our Seaway Pipeline.

§ The Midland terminal provides crude oil storage, pumpover and trade documentation services. The Midland terminal is the origination point for our Midland-to-ECHO 1 and 2 Pipeline Systems.

Texas Gulf Coast Offshore Oil Terminal. We are in the planning stage of developing a crude oil export terminal located offshore along the Texas Gulf Coast. The terminal would be capable of fully loading VLCC marine tankers, which have capacities of approximately 2 MMBbls and provide the most efficient and cost-effective solution to export crude oil to the largest international markets in Asia and Europe. We started front-end engineering and design work for the terminal in 2018 and filed our application for regulatory permitting with the Maritime Administration ("MARAD") in January 2019. Based on initial designs, the project would include onshore and offshore facilities capable of exporting crude oil at approximately 85,000 barrels per hour. A final investment decision for the project will be subject to the execution of long-term customer contracts and receiving state and federal permits.

18

Table of Contents

Corpus Christi Marine Terminal. We are joint owners of a marine crude oil terminal being constructed in Corpus Christi, Texas that will be capable of loading ocean-going vessels with either crude oil or condensate. Initial storage capacity of the terminal will be approximately 1.2 MMBbls. The facility will have access to production from both the Eagle Ford Shale and the Permian Basin through a connection with our Eagle Ford Crude Oil Pipeline System. The Corpus Christi marine terminal is expected to be placed into commercial service in the second quarter of 2019. Our 50% ownership interest in the terminal is held indirectly through our equity method investment in EF Terminals Corpus Christi LLC.

Crude oil marketing activities

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil and condensate 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 and condensate sales prices and the associated purchase and other costs, including those costs attributable to the use of our assets. In general, sales prices referenced in the underlying contracts are market-based and include pricing differentials for factors such as delivery location or crude oil quality. We use derivative instruments to mitigate our exposure to commodity price risks associated with our crude oil marketing activities. For a discussion of our commodity hedging program, see Part II, Item 7A of this annual report.

Our Crude Oil Pipelines & Services segment also includes a fleet of approximately 360 tractor-trailer tank trucks, the majority of which we lease and operate, that are used to transport crude oil.

Natural Gas Pipelines & Services Segment

Our Natural Gas Pipelines & Services business segment currently includes approximately 19,700 miles of natural gas pipeline systems that provide for the gathering, treating and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. This segment also includes our natural gas marketing activities.

Natural gas pipelines and related storage assets

Our natural gas pipeline systems gather, treat and transport natural gas from producing regions including the Permian, Eagle Ford Shale, Haynesville Shale, and the Piceance, San Juan and Greater Green River supply basins. In addition, certain of these pipelines receive natural gas production from Gulf of Mexico developments. Our natural gas pipelines redeliver the natural gas to processing facilities, electric generation plants, local gas distribution companies, industrial and municipal customers, storage facilities or other onshore pipelines.

The results of operations from our natural gas pipelines and related storage assets are primarily dependent upon the volume of natural gas gathered, treated, 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. See “Regulatory Matters” within this Part I, Items 1 and 2 discussion for additional information regarding governmental oversight of our natural gas pipelines.

Table of Contents

The following table presents selected information regarding our natural gas pipelines and related infrastructure at February 1, 2019:

				Net Capacity (1)		
Description of Asset	Location(s)	Ownership Interest	Pipeline Length (Miles)	Pipeline Capacity (MMcf/d)	Natural Gas Treating (MMcf/d)	Usable Storage (Bcf)
Texas Intrastate System (2)	Texas	Various	6,944	7,345	80	12.9
Acadian Gas System (2)	Louisiana	100.0%	1,312	3,100	--	1.3
Jonah Gathering System	Wyoming	100.0%	761	2,360	--	--
Piceance Basin Gathering System	Colorado	100.0%	190	1,800	--	--
San Juan Gathering System	New Mexico, Colorado	100.0%	6,073	1,750	440	--
Permian Basin Gathering System	Texas, New Mexico	100.0%	1,687	1,575	150	--
White River Hub (3)	Colorado	50.0%	10	1,500	--	--
Haynesville Gathering System	Louisiana, Texas	100.0%	357	1,300	810	--
BTA Gathering System(4)	Texas	100.0%	783	1,000	160	--
Fairplay Gathering System (4)	Texas	100.0% (5)	273	285	--	--
Indian Springs Gathering System (4)	Texas	80.0% (6)	145	160	--	--
Delmita Gathering System	Texas	100.0%	204	145	--	--
South Texas Gathering System	Texas	100.0%	518	143	--	--
Old Ocean Pipeline	Texas	50.0%	240	80	--	--
Big Thicket Gathering System	Texas	100.0%	250	60	--	--
Central Treating Facility	Colorado	100.0%	--	--	200	--
Total			19,747	22,603	1,840	14.2

(1) Net capacity amounts are based on our ownership interest or contractual right-of-use.
(2) Transportation services provided by these pipeline systems, in whole or part, are regulated by both federal and state governmental agencies.
(3) Services provided by the White River Hub are regulated by federal governmental agencies.
(4) Transportation services provided by these systems are regulated in part by state governmental agencies.
(5) This system includes approximately 52 miles of pipeline held under an operating lease.
(6) We proportionately consolidate our 80% undivided interest in the Indian Springs Gathering System.

On a weighted-average basis, overall utilization rates for our natural gas pipelines were approximately 58.3%, 57.1% and 57.4% during the years ended December 31, 2018, 2017 and 2016, 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 capacity fees are earned whether or not the shipper actually utilizes such capacity.

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

§ The Texas Intrastate System is comprised of the 6,319-mile Enterprise Texas pipeline system and the 625-mile Channel pipeline system. The Texas Intrastate System gathers, transports and stores natural gas from supply basins in Texas including the Permian Basin and Eagle Ford and Barnett Shales for delivery to local gas distribution companies, electric utility plants and industrial and municipal consumers. The system is also connected to regional natural gas processing plants and other intrastate and interstate pipelines. The Texas Intrastate System serves a number of commercial markets in Texas, including Corpus Christi, San Antonio/Austin, Beaumont/Orange and Houston, including the Houston Ship Channel industrial market.

We proportionately consolidate our undivided interests, which range from 22% to 80%, in 1,471 miles of pipeline. The Texas Intrastate System also includes our Wilson natural gas storage facility, which consists of a network of leased and owned underground salt dome storage caverns located in Wharton County, Texas with an aggregate 12.9 Bcf of usable storage capacity. Four of these caverns, comprising 6.9 Bcf of usable capacity, are held under an operating lease. The remainder of our Texas Intrastate System is wholly owned.

20

Table of Contents

§ The Acadian Gas System transports, stores and markets natural gas in Louisiana. The Acadian Gas System is comprised of the 582-mile Cypress pipeline, 429-mile Acadian pipeline, 275-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 utility 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 facility.

§ The Piceance Basin Gathering System gathers natural gas produced from the Piceance Basin in northwestern Colorado to our Meeker natural gas processing plant.

§ The San Juan Gathering System gathers and treats natural gas produced from the San Juan Basin in northern New Mexico and southern Colorado and delivers the natural gas either directly into interstate pipelines (if dry natural gas) or to regional natural gas plants, including our Chaco facility, for further processing (if rich natural gas) prior to being transported on interstate pipelines.

§ The Permian Basin Gathering System is comprised of the 982-mile Carlsbad pipeline system, the 671-mile Waha pipeline system and the 34-mile Orla pipeline system. The Permian Basin Gathering System gathers natural gas from the Permian Basin for delivery to regional natural gas processing plants, including our Chaparral, Carlsbad, South Eddy, Waha and Orla plants, and delivers residue and treated natural gas into our Texas Intrastate System and third party pipelines.

§ The White River Hub is a natural gas hub facility serving producers in the Piceance Basin. The facility enables producers to access six interstate natural gas pipelines and has a gross throughput capacity of 3 Bcf/d of natural gas. Our 50% ownership interest in White River Hub is held indirectly through our equity method investment in White River Hub, LLC.

§ The Haynesville Gathering System consists of the 214-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 and treats 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 BTA Gathering System, which is located in East Texas, gathers and treats natural gas from the Haynesville Shale and Bossier, Cotton Valley and Travis Peak formations. We acquired this system, along with our Panola and Fairway natural gas processing plants, in April 2017 for $191.4 million. For information regarding this acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

§ The Fairplay Gathering System gathers natural gas produced from the Cotton Valley formation within Panola and Rusk Counties in East Texas for delivery to regional markets.

§ The Indian Springs Gathering System, along with the Big Thicket Gathering System, gather natural gas from the Woodbine, Wilcox and Yegua production areas in East Texas.

§

The Delmita Gathering System gathers natural gas from the Frio-Vicksburg formation in South Texas for delivery to our Delmita natural gas processing plant.

§ The South Texas Gathering System gathers natural gas from the Olmos and Wilcox formations for delivery into our Texas Intrastate System, which delivers the natural gas to our South Texas natural gas processing plants.

21

Table of Contents

- The Old Ocean Pipeline transports natural gas from an injection point on our Texas Intrastate System near Maypearl, Texas for delivery to a pipeline interconnect at Sweeny, Texas. In May 2018, we announced the formation of a 50/50 joint venture with Energy Transfer Partners, L.P. ("ETP") to resume full service on the Old Ocean natural gas pipeline owned by ETP. The 24-inch diameter Old Ocean Pipeline originates in Maypearl, Texas in Ellis County and extends south approximately 240 miles to Sweeny, Texas in Brazoria County. ETP serves as operator of the pipeline, which has a gross natural gas transportation capacity of 160 MMcf/d. Repairs were completed on the pipeline, and it entered full service in January 2019.

In addition, both parties expanded their jointly owned North Texas 36-inch diameter natural gas pipeline, which is a component of our Texas Intrastate System. The expansion project was completed in January 2019 and provides us with additional natural gas takeaway capacity of 150 MMcf/d from West Texas, including deliveries into the Old Ocean Pipeline. The resumption of full service on the Old Ocean Pipeline and expansion of the North Texas Pipeline provide producers with additional takeaway capacity to accommodate growing natural gas production from the Delaware and Midland Basins.

- The Central Treating Facility is located in Rio Blanco County, Colorado and serves producers in the Piceance Basin. Natural gas delivered to the treating facility 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 of natural gas purchased from producers, regional natural gas processing plants and on the open market. Our natural gas marketing customers include local gas distribution companies and electric utility plants. The results of operations from our natural gas marketing activities are primarily dependent upon the difference, or spread, between natural gas sales prices and the associated purchase and other costs, including those costs attributable to the use of our 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, Piceance, Permian Basin 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 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.

Petrochemical & Refined Products Services Segment

Our Petrochemical & Refined Products Services business segment currently includes: (i) propylene production facilities, which include propylene fractionation units and a propane dehydrogenation ("PDH") facility, approximately 800 miles of pipelines, and associated marketing operations; (ii) a butane isomerization complex and related deisobutanizer ("DIB") operations, along with approximately 70 miles of associated pipelines; (iii) octane enhancement and high purity isobutylene ("HPIB") production facilities; (iv) refined products pipelines aggregating approximately 4,100 miles, terminals and associated marketing activities; and (v) marine transportation. This segment will also include our ethylene export terminal and related operations.

Propylene production and related operations

Our propylene production and related operations include seven propylene fractionation (or splitter) units, a PDH facility, approximately 800 miles of related pipelines, marine export dock infrastructure, and associated marketing activities.

Table of Contents

Propylene is a key feedstock used by the petrochemical industry. There are three grades of propylene; polymer grade ("PGP") with a minimum purity of 99.5%; chemical grade ("CGP") with a minimum purity of approximately 93-94%; and refinery grade ("RGP") with a purity of approximately 70%. In 2018, global demand for propylene (PGP and CGP combined) was estimated at 108 million tons. Propylene fractionation units separate RGP, which is a mixture of propane and propylene, into either PGP or CGP. The PDH facility produces PGP using propane feedstocks. The demand for PGP primarily relates to the manufacture of polypropylene, which has a variety of end uses including packaging film, fiber for carpets and upholstery, molded plastic parts for appliances, and automotive, houseware and medical products. CGP is a basic petrochemical used in the manufacturing of plastics, synthetic fibers and foams.

Our PDH facility entered full service in April 2018. The facility, which is located in Chambers County, Texas at our Mont Belvieu complex, has the capacity to produce up to 1.65 billion pounds per year, or approximately 25 MBPD, of PGP. At this nameplate production rate, the facility consumes approximately 35 MBPD of propane as feedstock. The PDH facility is integrated with our legacy Mont Belvieu propylene fractionation units, which provides us with operational reliability and flexibility for both the PDH facility and the fractionation units. The facility's construction was underwritten by long-term, fee-based contracts that feature minimum volume commitments.

To the extent we fractionate RGP for customers, we enter into toll processing arrangements. In our petrochemical marketing activities, we purchase RGP on the open market for fractionation at our splitter units and sell the resulting PGP to customers at market-based prices. The results of this marketing activity are primarily dependent upon the difference, or spread, between the sales prices of the PGP and the associated purchase and other costs, including the costs attributable to use of our propylene production assets and related infrastructure. To limit the exposure of these marketing activities to price risk, we attempt to match the timing and price of our feedstock purchases with those of the sales of end products.

Our petrochemical marketing activities also include the purchase of propane for our PDH facility to process into PGP, which is then sold to customers under long-term sales contracts (take-or-pay arrangements) that feature minimum volume commitments and contractual pricing that minimizes our commodity price risk.

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. In order to meet the growing international demand for PGP, this business also includes export assets located at EHT that are capable of loading up to 5,000 metric tons per day of refrigerated PGP.

The following table presents selected information regarding our propylene production facilities at February 1, 2019:

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
PDH facility:					
Mont Belvieu	Texas	100.0%		25	25

(1) We proportionately consolidate a 66.7% undivided interest in three of the propylene splitters, 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 PGP at our propylene fractionation units and PDH facility located at the Mont Belvieu hub and CGP at our BRPC facility located in Baton Rouge, Louisiana. On a weighted-average basis, the overall utilization rate of our propylene production facilities was approximately 86.7%, 89.9% and 81.9% during the years ended December 31, 2018, 2017 and 2016, respectively.

Table of Contents

The following table presents selected information regarding our propylene pipelines at February 1, 2019:

Description of Asset	Location(s)	Ownership Interest		Length (Miles)
Lou-Tex Propylene Pipeline	Texas, Louisiana	100.0%		263
Texas City RGP Gathering System	Texas	100.0%		167
North Dean Pipeline System	Texas	100.0%		157
Propylene Splitter PGP Distribution System	Texas	100.0%		82
Louisiana RGP Gathering System	Louisiana	100.0%		63
Lake Charles PGP Pipeline	Texas, Louisiana	50.0%	(1)	27
La Porte PGP Pipeline	Texas	80.0%	(2)	20
Sabine Pipeline	Texas, Louisiana	100.0%		15
Total				794

(1) We proportionately consolidate our undivided interest in the Lake Charles PGP Pipeline.
(2) We own an 80% consolidated interest in the La Porte PGP Pipeline through our majority owned subsidiaries, La Porte Pipeline Company, L.P. and La Porte Pipeline GP, L.L.C.

The maximum number of barrels per day that our petrochemical pipelines can transport depends on the operating rates 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 125 MBPD, 106 MBPD and 121 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

The Lou-Tex Propylene pipeline is used to transport CGP from Sorrento, Louisiana to Mont Belvieu. In June 2015, we announced plans to convert the Lou-Tex Propylene pipeline from CGP to PGP service. This conversion is scheduled for completion in 2020.

With the exception of the Lake Charles PGP Pipeline in Louisiana, we operate all of our propylene production assets and related pipelines.

Isomerization and related operations

We own and operate three isomerization units at our Mont Belvieu complex having an aggregate processing capacity of 116 MBPD that comprise the largest commercial isomerization facility in the U.S. These operations also include a 70-mile pipeline system used to transport high-purity isobutane from the Mont Belvieu hub to Port Neches, Texas. We own and operate this pipeline system.

The demand for commercial isomerization services depends upon the energy industry's requirements for isobutane and high-purity isobutane in excess of the isobutane produced through the process of NGL fractionation and refinery operations. Isomerization units convert normal butane feedstock into mixed butane, which is a stream of isobutane and normal butane. DIB units, of which we own and operate nine located at our Mont Belvieu complex, then separate the isobutane from the normal butane. 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 primary uses of isobutane are for the production of propylene oxide, isooctane, isobutylene and alkylate for motor gasoline. We also use certain of our DIB units to fractionate mixed butanes originating from NGL fractionation activities, imports and other sources into isobutane and normal butane. The operating flexibility provided by our multiple standalone DIBs enables us to capture market opportunities resulting from fluctuations in demand and prices for different types of butanes.

The results of operations from our isomerization business are generally dependent on the volume of normal and mixed butanes processed and the level of toll processing fees charged to customers.

Our isomerization 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. On a weighted-average basis, the utilization rates of our isomerization facility were approximately 92.2%, 92.2% and 93.1% during the years ended December 31, 2018, 2017 and 2016, respectively.

Table of Contents

In January 2018, we announced plans to expand our butane isomerization facility by up to 30 MBPD of incremental capacity. The expansion is supported by long-term agreements to provide butane isomerization, storage and related pipeline services. We currently expect this project to be completed during the fourth quarter of 2021.

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

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. We measure the utilization of our octane enhancement facility in terms of its combined isooctane, isobutylene and MTBE production volumes, which averaged 24 MBPD, 23 MBPD and 19 MBPD during the years ended December 31, 2018, 2017 and 2016, respectively.

We also own and operate a facility located on the Houston Ship Channel that produces up to 4 MBPD of HPIB and includes an associated storage facility with 0.6 MMBbls of related product storage capacity. The primary feedstock for this plant, an isobutane/isobutylene mix, is produced by our octane enhancement facility. HPIB is used in the production 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 88.9%, 75.9% and 58.4% for the years ended December 31, 2018, 2017 and 2016, respectively.

The results of operations from our octane enhancement and HPIB facilities are generally dependent on the level of production volumes and the difference, or spread, between the sales prices of the products and the associated feedstock purchase costs and other operating expenses.

Isobutane Dehydrogenation Unit. In January 2017, we announced plans to construct an isobutane dehydrogenation ("iBDH") unit at our Mont Belvieu complex that is expected to have the capability to produce 425,000 tons of isobutylene per year. The project, which is underwritten by long-term customer contracts, is expected to be completed in the fourth quarter of 2019. Isobutylene produced by the new plant will also provide additional feedstocks for our downstream octane enhancement and petrochemical facilities.

Historically, steam crackers and refineries have been the major source of propane and butane olefins for downstream use. However, with the increased use of light-end feedstocks such as ethane, the need for on-purpose olefins production has increased. Like our PDH facility, the iBDH plant will help meet market demand where traditional supplies have been reduced. The iBDH plant will increase our production of high purity and low purity isobutylene, both of which are used as feedstocks to manufacture lubricants, rubber products and alkylate for gasoline blendstocks, as well as MTBE for export.

Refined products services
Our refined products services business includes refined products pipelines aggregating approximately 4,100 miles, terminals and associated marketing activities.

Refined products pipelines. We own and operate the TE Products Pipeline, which is a 3,278-mile pipeline system comprised of 2,953 miles of regulated interstate pipelines and 325 miles of unregulated intrastate Texas pipelines. The system primarily transports refined products 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 a location near Philadelphia, Pennsylvania. East of Seymour, Indiana, the TE Products Pipeline is primarily dedicated to NGL transportation service. The refined products transported by the TE Products Pipeline are produced by refineries and include motor gasoline and distillates.

25

Table of Contents

The results of operations for this pipeline system are 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. See "Regulatory Matters" within this Part I, Items 1 and 2 discussion for additional information regarding governmental oversight of our liquids pipelines, including tariffs charged for transportation services.

The maximum number of barrels per day that our TE Products Pipeline can transport depends on the operating balance achieved at a given point in time between various segments of the system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rate of this pipeline in terms of throughput. Aggregate throughput volumes by product type for the TE Products Pipeline were as follows for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Refined products transportation (MBPD)	456	456	474
Petrochemical transportation (MBPD)	148	156	164
NGL transportation (MBPD)	71	57	55

The TE Products Pipeline system includes five non-regulated refined products truck terminals and 18.5 MMBbls of aggregate storage capacity.

We also own a 50% equity interest in the Centennial Pipeline, which is a 795-mile refined products pipeline that extends from 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 (1.2 MMBbls net to our ownership interest). Although the Centennial Pipeline is currently idle, we continue to evaluate potential projects with our joint venture partner that could repurpose the line.

Refined products marine terminals. We own and operate marine terminals located on the Neches River near Beaumont, Texas that handle refined products along with crude oil. Our Beaumont facilities include five deep-water ship docks, three barge docks and access to approximately 7.8 MMBbls of aggregate refined products storage capacity.

We also handle refined products at EHT on the Houston Ship Channel. In addition to providing vessel loading and unloading services for refined products, EHT's refined products operations include 2.0 MMBbls of aggregate storage capacity through the use of 24 above-ground storage tanks.

The results of operations for these marine terminals are primarily dependent upon the volume handled and the associated storage and other fees we charge.

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 grade and delivery location. We use derivative instruments to mitigate our exposure to commodity price risks associated with our refined products marketing activities. For a discussion of our commodity hedging program, see Part II, Item 7A of this annual report.

Marine transportation

Our marine transportation business consists of 64 tow boats and 148 tank barges used to transport refined products, crude oil, asphalt, condensate, heavy fuel oil, LPG and other petroleum products along key U.S. inland and intracoastal waterway systems. The marine transportation industry uses tow boats as power sources and tank barges for freight capacity. Our marine transportation assets serve refinery and storage terminal customers along the Mississippi River, the intracoastal waterway between Texas and Florida and the Tennessee-Tombigbee Waterway system. We own and operate shipyard and repair facilities located in Houma and Morgan City, Louisiana and marine fleeting facilities located in Bourg, Louisiana and Channelview, Texas.

Table of Contents

The results of operations of our marine transportation business are generally dependent upon the level of fees charged (e.g., set day rates or fee per cargo movement) to transport petroleum products.

Our fleet of marine vessels operated at an average utilization rate of 93.5%, 86.3% and 85.2% during the years ended December 31, 2018, 2017 and 2016, respectively.

Our marine transportation business is subject to regulation, including by the U.S. Department of Transportation (“DOT”), Department of Homeland Security, U.S. Department of Commerce and the U.S. Coast Guard (“USCG”). For information regarding these regulations, see “Regulatory Matters – Federal Regulation of Marine Operations,” within this Part I, Items 1 and 2 discussion.

Ethylene export terminal and related operations

We are constructing an ethylene export terminal located at Morgan’s Point on the Houston Ship Channel. When completed, the terminal, which we will operate, is expected to have an export capacity of approximately 2.2 billion pounds of ethylene per year, with loading rates of 2.2 million pounds per hour, and feature on-site refrigerated storage for 66 million pounds of ethylene. The project, which is underwritten by long-term customer commitments, is expected to begin limited commercial service in the fourth quarter of 2019, with full operations expected in the fourth quarter of 2020 once certain refrigeration assets are complete. We own a 50% equity interest in Enterprise Navigator Ethylene Terminal LLC, which owns the export facility.

In the second quarter of 2019, we expect to complete a project at our Mont Belvieu storage complex that repurposes a large, high-capacity ethane storage well into ethylene service. The new 5.3 MMBbl ethylene storage cavern will feature an injection/withdrawal rate of approximately 210,000 pounds per hour (or approximately 2,000 barrels per hour) and be expandable to 420,000 pounds per hour (or approximately 4,000 barrels per hour). There are eight third party ethylene pipelines within a half-mile of the new high-capacity well, which provides us with significant connection opportunities.

In further support of our ethylene capabilities, we are building a 24-mile ethylene pipeline extending from our Mont Belvieu complex to Bayport, Texas. The new pipeline will have the potential to connect both producing and consuming customers located south of the Houston Ship Channel to our ethylene storage facility in Mont Belvieu. The pipeline between our Mont Belvieu complex and Morgan’s Point terminal is expected to be completed in 2019, with the remaining sections completed in 2020.

Regulatory Matters

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

Environmental, Safety and Conservation

The safe operation of our pipelines and other assets is a top priority. 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 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 similar state requirements, including general industry standards, record keeping requirements and monitoring of occupational exposures of employees.

Certain of our facilities are also 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 certain chemicals, flammable gases or liquids at or above a specified threshold (as defined in the regulations). In addition, we are subject to 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

27

Table of Contents

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.

Pipeline Safety

We are subject to extensive regulation by the DOT as 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. The DOT regulates natural gas and hazardous liquids pipelines through its Pipeline and Hazardous Materials Safety Administration ("PHMSA"). We believe we are in material compliance with DOT regulations.

We are also 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. These regulations require 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 pipeline segments in HCAs 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.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the "Pipeline Safety Act") provides for regulatory oversight of the nation's pipelines, penalties for violations of pipeline safety rules, and other DOT matters. The Pipeline Safety Act currently provides for penalties involving non-compliance with DOT regulations of $0.2 million for a single violation and a maximum fine for the most serious pipeline safety violations (e.g., those violations resulting in deaths, injuries or major environmental harm) of $2.1 million per incident. In addition, the Pipeline Safety Act includes additional safety requirements for newly constructed pipelines.

In June 2016, the "Securing America's Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016" (the "SAFE PIPES Act") was signed into law. The SAFE PIPES Act extends the PHMSA's statutory mandate through 2019 and establishes or continues the development of requirements affecting pipeline safety including, but not limited to, the following: (i) providing the PHMSA with additional authority to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities, without prior notice or an opportunity for a hearing; (ii) obligating the PHMSA to develop safety standards for natural gas storage facilities; and (iii) requiring the PHMSA to complete certain of the outstanding mandates under existing legislation and to report to Congress on the status of overdue rulemakings.

DOT regulations have incorporated by reference American Petroleum Institute Standard 653 ("API 653") as the industry standard for the inspection, repair, alteration and reconstruction of above-ground storage tanks. API 653 requires that above-ground storage tanks undergo regularly scheduled maintenance, which may result in significant and unanticipated expenditures for repairs or upgrades that are deemed necessary to ensure the continued safe and reliable operation of such tanks.

PHMSA has issued proposed new or revised regulations under either the Pipeline Safety Act or the SAFE PIPES Act that may impact our pipelines. The proposed new or revised regulations for hazardous liquid pipelines include: (i) extending the reporting requirements to all hazardous liquid gravity and gathering lines; (ii) requiring inspections of pipelines in areas affected by extreme weather; (iii) requiring periodic inline integrity assessments of hazardous liquid
28

Table of Contents

pipelines in all locations; (iv) modifying the provisions for making pipeline repairs; (v) requiring all pipelines subject to integrity management requirements be capable of accommodating inline inspection tools within 20 years, with certain exceptions; and (vi) clarifying of other regulations to improve compliance. The notice regarding these regulations was issued in October 2015 and the final rule remains pending.

In March 2016, the PHMSA issued proposed new safety regulations for natural gas transmission pipelines that broaden the scope of safety coverage in several ways, including but not limited to: (i) modifying the regulation of gathering lines by eliminating the exemption from reporting requirements for gas gathering line operators and revising the definition for gathering lines; (ii) adding new assessment and revising repair criteria for pipeline segments in HCAs and establishing repair criteria for pipelines that are outside of HCAs; (iii) expanding the scope of the regulations to include pipelines located in areas of Medium Consequence Areas ("MCAs"); (iv) adding a requirement to test pipelines built before 1970, which are currently exempt from certain pipeline safety requirements; (v) modifying the way that pipeline operators secure and inspect transmission pipeline infrastructure following extreme weather events; (vi) clarifying requirements for conducting risk assessment associated with integrity management activities; (vii) expanding mandatory data collection and integration requirements associated with integrity management activities, including data validation; (viii) requiring new safety features for pipeline "pig" launchers and receivers; and (ix) requiring a systematic approach to verify a pipeline's maximum allowable operating pressure and requiring operators to report maximum allowable operating pressure exceedances. A final rule regarding these proposals remains pending.

PHMSA has also issued a final rule, which became effective in January 2019, that amends pipeline safety regulations covering the types, design, and installation of plastic materials that can be used to transport natural gas. The new rule permits the use of PVC pipe, adopts a variety of applicable industry standards, and revises regulations related to storage and handling, component design, valve design, standard fittings, and pipe testing associated with the use of plastic pipe.

In response to the SAFE PIPES Act, PHMSA issued an interim final rule adopting federal safety regulations and reporting requirements for underground natural gas storage facilities in December 2016. Petitions for review of the interim final rule are pending at the U.S. Court of Appeals for the Fifth Circuit, which is holding the proceeding in abeyance. In June 2017, PHMSA partially stayed enforcement of the interim rule's new safety standards until one year after publication of the final rule.

The development and/or implementation of more stringent requirements pursuant to regulations implementing all of the requirements of the Pipeline Safety Act or the SAFE PIPES Act may result in us incurring significant and unanticipated expenditures to comply with such standards. Until the proposed regulations are finalized, the impact on our operations, if any, 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: the 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"); the OSHA; the Emergency Planning and Community Right to Know Act; the National Historic Preservation 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.

29

Table of Contents

We believe our operations are in material compliance with existing environmental and safety laws and regulations and that our compliance with such 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. 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 regulated, 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. These laws and regulations may also require that we (i) 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 levels of air emissions, (ii) obtain and strictly comply with the requirements of air permits containing various emission and operational limitations, or (iii) utilize specific emission control technologies to limit emissions.

Increasingly, environmental groups are challenging requests to modify or renew permits and seeking to apply more stringent provisions on applicants. Our failure to comply with applicable requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations, including enforcement actions, and our inability to renew or secure a needed modification to an existing permit could adversely affect our operations. We may also be required to incur certain capital expenditures for air pollution control equipment in connection with obtaining and maintaining permits and approvals for air emissions.

Water Quality

The CWA and comparable state laws impose strict controls on the discharge of petroleum 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 into navigable waters or groundwater. Federal spill prevention control and countermeasure mandates 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 monitoring and other requirements. The CWA 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, deepwater ports, offshore production 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 Office of Pipeline Safety ("OPS") or the EPA, as appropriate. Numerous states have enacted laws similar to the OPA. Under the OPA and similar state laws, responsible parties for a regulated facility from which 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.

Table of Contents

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 historical operations, we believe any such contamination could be controlled or remedied; however, 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 U.S. 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 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 NGL, refined products and crude oil pipeline systems have interstate common carrier movements subject to regulation by the FERC under the Interstate Commerce Act ("ICA"). Pipelines providing such movements (referred to as "interstate liquids pipelines") include, but are not limited to, the following: ATEX, Aegis, Dixie Pipeline, TE Products Pipeline, Front Range Pipeline, Mid-America Pipeline System, Seaway Pipeline, Seminole NGL Pipeline and Texas Express Pipeline. These pipelines are owned by legal entities whose movements are subject to FERC regulation, including periodic reporting requirements. For example, ATEX, Aegis and the TE Products Pipeline are owned by Enterprise TE Products Pipeline Company LLC ("Enterprise TE"), which provides FERC-regulated movements.

Table of Contents

The ICA prescribes that the 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. The 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. For the five-year period ending June 30, 2021, we are permitted to adjust the indexed rate ceiling annually by PPI plus 1.23%. In any year in which the index is negative due to a decline in the PPI, a pipeline must file to lower its rates if they otherwise would be above the indexed rate ceiling. Otherwise, a pipeline is permitted to increase its rates to the new ceiling. 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 December 2014, Seaway submitted an application requesting market-based rate setting authority. Certain parties filed protests to the application. In September 2015, the FERC issued an order setting the matter for hearing. In December 2016, an administrative law judge issued an initial decision in the market-based rate proceeding (“2016 Initial Decision”) finding that the FERC should grant Seaway’s application for market-based rates. In May 2018, the FERC issued an order affirming the initial decision’s finding that Seaway lacks market power in the applicable markets, thereby granting Seaway market-based rate authority.

In October 2016, the FERC sought comments regarding potential modifications to its policies for evaluating changes in oil pipeline indexed rates and the associated reporting requirements. The FERC observed that some pipelines continue to obtain additional index rate increases despite reporting on Form No. 6 that their revenues exceed their costs. The FERC is proposing a new policy that would deny proposed index increases if a pipeline’s Form No. 6 reflects (i) revenues that exceed the total cost-of-service by 15% for the two preceding years or (ii) the proposed increase in the rate index exceeds the percentage change in the pipeline’s annual costs by 5%. The FERC is also considering requiring pipelines to file additional information for crude and refined product pipelines, non-contiguous systems and major pipeline systems. Comments on these proposals were filed with the FERC through March 2017; however, the FERC has taken no position at this time and we are unable to predict the outcome of this proceeding.

In March 2018, the FERC issued a Revised Policy Statement on the Treatment of Income Taxes (the “Revised Policy”). The Revised Policy reversed a 13-year old policy that permitted a pipeline owned by a master limited partnership (“MLP”) to recover an income tax allowance (“ITA”) in its cost-of-service rates, if it could demonstrate that the ultimate owners of the pipeline (i.e., the unitholders of the MLP) have an actual or potential income tax liability. In July 2018, the FERC, in an Order on Rehearing, decided to provide pipeline MLPs the opportunity to argue for inclusion of an ITA in cost-of-service rates on a case-by-case basis, as opposed to having no opportunity to recover an ITA. Two third parties filed petitions for review of the Revised Policy and Order on Rehearing in the D.C. Circuit in September 2018. We are unable to predict the outcome of these pending petitions for review.

Table of Contents

The Revised Policy and Order on Rehearing do not impact oil and liquids pipelines with market-based rate authority, or those that charge "settlement rates," and have no immediate effect on oil and liquid pipelines with rates set using the indexing methodology, given that the current index will remain in effect through June 30, 2021. However, following issuance of the Revised Policy, the FERC now requires oil and liquids pipelines owned by MLPs to remove the ITA from their cost-of-service reporting in FERC Form No. 6. The FERC has stated that it will incorporate the effects of this change when it commences its next five-year review of the oil pipeline index in 2020, for rates that will take effect on July 1, 2021. The FERC has not yet commenced this proceeding and we are unable predict the outcome at this time.

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.

FERC Regulation – Natural Gas Pipelines and Related Matters

Certain of our intrastate natural gas pipelines, including the Texas Intrastate System and 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, along with 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 the 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.

In July 2018, the FERC issued a final rule to address the impact of the Tax Cuts and Jobs Act on cost-of-service rates for jurisdictional natural gas pipelines. The final rule primarily impacts interstate pipelines regulated under the NGA. With respect to intrastate pipelines regulated by the FERC under the NGPA, the rule requires an intrastate pipeline with rates on file with a state regulatory agency to file with the FERC a new rate election for its interstate rates if the state rates are reduced to reflect the reduced income tax rates adopted in the Tax Cuts and Jobs Act. As of the date of this report, we have not been required to refile the rates for our intrastate systems as a result of this rule.

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 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 manipulation of energy markets. 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 natural 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 NGPA, or any rules, regulations or orders of the FERC, were $1.2 million per day per violation as of January 2018.

33

Table of Contents

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. 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.

Federal Regulation of Marine Operations

The operation of tow boats, barges and marine equipment create 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.-flagged 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 climate change and the environmental effects of greenhouse gas emissions and their associated consequences on 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 a long-term 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.

In response to scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases, including gases associated with oil and natural 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 (individually or in regional cooperation), 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.

Actions have also taken place at the international level, with the U.S. being involved. 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 are under discussion and have and may continue to result in additional actions involving greenhouse gases.

34

Table of Contents

These federal, regional and state measures generally apply to industrial sources (including facilities in the oil and gas sector) and suppliers and distributors of fuel, and could increase the operating and compliance costs of our pipelines, natural gas processing plants, fractionation plants and other facilities, and the costs of certain sale and distribution activities. These regulations could also adversely affect market demand and pricing for products handled by our midstream network, 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.

Competition

NGL Pipelines & Services

Within their respective market areas, our natural gas processing plants and related NGL marketing activities encounter competition primarily from independent processors, major integrated oil companies, and financial institutions with commodity trading platforms. 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 business are major integrated 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 export terminal operations compete with those operated by major oil and gas and chemical companies and other midstream service providers primarily in terms of loading and offloading throughput capacity and access to related pipeline and storage infrastructure.

We compete with a number of NGL fractionators in Kansas, Louisiana, New Mexico and Texas. 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.

Crude Oil Pipelines & Services

Within their respective market areas, our 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 commodity trading platforms and independent crude oil gathering and marketing companies. The crude oil business can be characterized by intense competition for supplies of crude oil at the wellhead. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and market hubs.

35

Natural Gas Pipelines & Services

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 natural gas gathering business include independent gas gatherers and major integrated energy companies. 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.

Petrochemical & Refined Products Services

We compete with numerous producers of PGP, which include many of the major refiners and petrochemical companies located along the Gulf Coast, in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from major integrated oil companies and various petrochemical companies that have varying levels of financial and personnel resources and competition generally revolves around product 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, the pipeline's most significant competitors are third party pipelines in the areas where it delivers products. Competition among common carrier pipelines is based primarily on transportation fees, quality of customer service and proximity to end users. Trucks, barges and railroads competitively deliver products into some of the markets served by our TE Products Pipeline and river terminals. The TE Products Pipeline also 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 performance and price. Also, substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business.

For a discussion of the general risks involving competition, see "We face competition from third parties in our midstream energy business" under Part I, Item 1A of this annual report.

Seasonality

Although the majority of our businesses are not materially affected by seasonality, certain aspects of our operations are impacted by seasonal changes such as tropical weather events, energy demand in connection with heating and cooling requirements and for the summer driving season. Examples include:

§ Our operations along the Gulf Coast, including those at our Mont Belvieu complex, may be affected by weather events such as hurricanes and tropical storms, which generally arise during the summer and fall months.

§ Residential demand for natural gas typically peaks during the winter months in connection with heating needs and during the summer months for power generation for air conditioning. These seasonal trends affect throughput volumes on our natural gas pipelines and associated natural gas storage levels and marketing results.

§ Due to increased demand for fuel additives used in the production of motor gasoline, our isomerization and octane enhancement businesses experience higher levels of demand during the summer driving season, which typically occurs in the spring and summer months. Likewise, shipments of refined products and normal butane experience similar changes in demand due to their use in motor fuels.

36

Table of Contents

§ Extreme temperatures and ice during the winter months can negatively affect our trucking and inland marine operations on the upper Mississippi and Illinois rivers.

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 complex is 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.

Available Information

As a publicly traded partnership, we electronically file certain documents with the U.S. 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. The SEC maintains a website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

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.

Table of Contents

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 prices 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 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 customers do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, propylene, refined products and/or crude oil and long-term take-or-pay agreements.

Crude oil and natural gas prices have been volatile in recent years. For example, crude oil prices (based on WTI as measured by the NYMEX) ranged from a high of $76.41 per barrel to a low of $26.21 per barrel in the three year period ending December 31, 2018. Likewise, natural gas prices (based on Henry Hub as measured by the NYMEX) ranged from a high of $4.84 per MMBtu to a low of $1.64 per MMBtu over the same three-year period.

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 crude 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 crude 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 risks 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 primarily from existing domestic resource basins, which naturally deplete over time. To offset this natural decline, our facilities 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 logistics assets are located could result in a decrease in volumes handled by our assets, which could have a material adverse effect on our financial position, results of operations and cash flows.

Table of Contents

For a discussion regarding our current commercial outlook for 2019, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Outlook for 2019" 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 crude oil and natural gas, for any such production on the basis of many factors, including but not limited to geographic proximity to the production, costs of connection, available capacity, rates and access to markets.

Our NGL, refined products 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 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 commodity 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 natural gas gathering business 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.

Both we and our competitors make significant investments in new energy infrastructure to meet anticipated market demand. The success of our projects depends on utilization of our assets. Demand for our new projects may change during construction, and our competitors may make additional investments or redeployments of assets that compete with our projects and existing assets. If either our investments or construction by competitors in the markets we serve result in excess capacity, our facilities and assets could be underutilized, which could cause us to reduce rates for our services, and to reduce the returns on our investments and value of our assets.

A significant increase in competition in the midstream energy industry, including construction of new assets or redeployment of existing assets by our competitors, could have a material adverse effect on our financial position, results of operations and cash flows.

Table of Contents

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

As of December 31, 2018, we had $23.75 billion in principal amount of consolidated senior long-term debt outstanding and $2.67 billion in principal amount of junior subordinated debt 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 for 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 7 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.

Table of Contents

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 expenditures for 2018 reflected $4.49 billion of cash payments for capital projects and other investments. Based on information currently available, we expect our total capital expenditures for 2019 to approximate $3.5 billion to $3.9 billion, which includes $350 million for sustaining capital projects. 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 sustained 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. Accordingly, increased costs of equity and debt will make returns on capital expenditures with proceeds from such capital less accretive on a per unit basis.

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 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. 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 operational, 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, legal and economic 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;

41

- § 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 crude oil or 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 or construction of a new petrochemical facility) 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.

Several of our assets have been in service for many years and require significant expenditures to maintain them. As a result, our maintenance or repair costs may increase in the future.

Our pipelines, terminals and storage assets are generally long-lived assets, and many of them have been in service for many years. The age and condition of our assets could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our results of operations, financial position or cash flows, as well as our ability to make cash distributions to our unitholders.

The inability to continue to access lands owned by third parties could adversely affect our operations and have a material adverse effect on our financial position, results of operations and cash flows.

Our ability to operate our pipeline systems on certain lands owned by third parties will depend on our maintaining existing rights-of-way and obtaining new rights-of-way on those lands. We are parties to rights-of-way agreements, permits and licenses authorizing land use with numerous parties, including private land owners, governmental entities, Native American tribes, rail carriers, public utilities and others. Our ability to secure extensions of existing agreements, permits and licenses is essential to our continuing business operations, and securing additional rights-of-way will be critical to our ability to pursue expansion projects. We cannot provide any assurance that we will be able to maintain access to all existing rights-of-way upon the expiration of the current grants, that all of the rights-of-way will be obtained in a timely fashion or that we will acquire new rights-of-way as needed.

In particular, various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, Bureau of Land Management, and the Office of Natural Resources Revenue, along with each Native American tribe, promulgate and enforce regulations pertaining to natural gas and oil operations on Native American tribal lands. These regulations and approval requirements relate to such matters as drilling and production requirements and environmental standards. In addition, each Native American tribe is a sovereign nation having the right to enforce laws and regulations and to grant approvals independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to operators and contractors conducting operations on Native American tribal lands. One or more of these factors may increase our cost of doing business on Native American tribal lands and impact the viability of, or prevent or delay our ability to conduct our operations on such lands.

Table of Contents

Furthermore, whether we have the power of eminent domain for our pipelines varies from state to state, depending upon the type of pipeline and the laws of the particular state and the ownership of the land to which we seek access. When we exercise eminent domain rights or negotiate private agreements, we must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect our business if we were to lose the right to use or occupy the property on which our pipelines are located.

We may face opposition to the operation of our pipelines and facilities from various groups.

We may face opposition to the operation of our pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such 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 to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

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. From time to time, we 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.

Table of Contents

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.

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

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

If one or more facilities or electronic systems that we own or that deliver products to us or that supply our facilities are damaged by severe weather or any other disaster, accident, catastrophe, terrorist attack or other 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.

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.

Table of Contents

A cyber-attack on our information technology ("IT") systems could affect our business and assets, and have a material adverse effect on our financial position, results of operations and cash flows.

We rely on our IT systems to conduct our business, as well as systems of third-party vendors. These systems include information used to operate our assets, as well as cloud-based services. These systems are subject to possible security breaches and cyber-attacks.

Cyber-attacks are becoming more sophisticated, and U.S. government warnings have indicated that infrastructure assets, including pipelines, may be specifically targeted by certain groups. These attacks include, without limitation, malicious software, ransomware, attempts to gain unauthorized access to data, and other electronic security breaches. These attacks may be perpetrated by state-sponsored groups, "hacktivists", criminal organizations or private individuals (including employee malfeasance). These cybersecurity risks include cyber-attacks on both us and third parties who provide material services to us. In addition to disrupting operations, cyber security breaches could also affect our ability to operate or control our facilities, render data or systems unusable, or result in the theft of sensitive, confidential or customer information. These events could also damage our reputation, and result in losses from remedial actions, loss of business or potential liability to third parties.

We do not carry insurance specifically for cybersecurity events; however, certain of our insurance policies may allow for coverage of associated damages resulting from such events. 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.

Failure of our critical IT systems could have an adverse impact on our business, financial condition, results of operations and cash flows, as well as our ability to pay cash distributions.

We rely on IT systems to operate our assets and manage our businesses. We depend on these systems to process, transmit and store electronic information, including financial records and personally identifiable information such as employee, customer, investor and payroll data, and to manage or support a variety of business processes, including our supply chain, pipeline and storage operations, gathering and processing operations, financial transactions, banking and numerous other processes and transactions. Some of these IT systems are proprietary and custom designed for our business, while others are based upon or reside on commercially available technologies.

Failures of these IT systems, whether due to power failures, a cybersecurity event or other reason, could result in a breach of critical operational or financial controls and lead to a disruption of our operations, commercial activities or financial processes. Such failures could adversely affect our results of operations, financial position or cash flow, as well as our ability to pay cash distributions in a timely manner. State and federal cybersecurity legislation could also impose new requirements, which could increase our cost of doing business.

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, or our risk management policies and procedures are not followed. Adverse economic conditions (e.g., a significant decline in energy commodity prices that negatively impact the cash flows of oil and gas producers) increase the risk of nonpayment or performance by our hedging counterparties.

Table of Contents

See Part II, Item 7A of this annual report and Note 14 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.

We may incur credit risk to the extent customers do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, crude oil, petrochemicals and refined products and long-term contracts with minimum volume commitments or fixed demand charges. 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 in our industry may increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings. 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 Mountains, Northeast and Midwest regions of the U.S. We have a concentration of trade receivable balances due from domestic and international 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.

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

Our risk management policies cannot eliminate all commodity price risks. In addition, any noncompliance 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 with respect to price risks 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 commodity for physical delivery to third party users, such as producers, wholesalers, local distributors, independent refiners, marketing companies or major integrated 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 our sales 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 in 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, 2018, we had $26.15 billion in principal amount of consolidated fixed-rate debt outstanding, including current maturities thereof. Due to the short term nature of commercial paper notes, we view the interest rates charged in connection with these instruments as variable.

Table of Contents

The Board of Governors of the Federal Reserve System raised benchmark interest rates three times during 2017, four times during 2018, and has stated that it expects to raise rates again in 2019. 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.

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.

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.

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 in pipeline 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 total, our pipeline integrity costs for the years ended December 31, 2018, 2017 and 2016 were $122.0 million, $91.1 million and $103.7 million, respectively. Of these annual totals, we charged $71.8 million, $52.3 million and $55.8 million to operating costs and expenses during the years ended December 31, 2018, 2017 and 2016, 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 $126 million for 2019.

For additional information regarding the pipeline safety regulations, the Pipeline Safety Act and the SAFE PIPES Act, see "Regulatory Matters – Safety Matters – Pipeline Safety" included under Part I, Items 1 and 2 of this annual report.

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 the 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.

Table of Contents

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 developments include the following items.

Greenhouse Gases/Climate Change

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

The adoption and implementation of any federal, state or local regulations imposing reporting obligations on, or limiting emissions of 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 greenhouse gas emissions (whether emitted by our operations or associated with fuel that we supply into the markets), pay taxes related to 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, which may limit our access to, or otherwise cause us to reduce our participation in, certain market activities. 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.

In addition, due to concerns over climate change, numerous countries around the world have adopted or are considering adopting laws or regulations to reduce greenhouse gas emissions. It is not possible to know how quickly renewable energy technologies may advance, but if significant additional legislation and regulation were enacted, the increased use of renewable energy could ultimately reduce future demand for hydrocarbons. 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 crude oil and natural 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 crude 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 businesses and have a material adverse effect on our financial position, results of operations and cash flows.

See “Regulatory Matters” under Part I, Items 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. State regulatory agencies regulate our intrastate natural gas and NGL pipelines, intrastate storage facilities and gathering lines.
48

Table of Contents

Our intrastate NGL and natural gas pipelines are subject to regulation in many states, including Colorado, Kansas, Louisiana, New Mexico, Texas and Wyoming. To the extent our intrastate natural gas 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, Items 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. However, in any year in which the index is negative, a pipeline must file to lower its rates if its rates would be above the indexed rate ceiling. 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.

In October 2016, the FERC sought comments regarding potential modifications to its policies for evaluating changes in oil pipeline indexed rates and the associated reporting requirements. The FERC observed that some pipelines continue to obtain additional index rate increases despite reporting on Form No. 6 that their revenues exceed their costs. The FERC is proposing a new policy that would deny proposed index increases if a pipeline’s Form No. 6 reflects (i) revenues that exceed the total cost-of-service by 15% for the two preceding years or (ii) the proposed increase in the rate index exceeds the percentage change in the pipeline’s annual costs by 5%. 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.

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.

Table of Contents

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 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 requirements, 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 currently qualify as an end-user. In addition, the vast majority of our derivative transactions are currently transacted through a Derivatives Clearing Organization, and we believe our use of the end-user exception will likely not be necessary on a routine basis. We will also 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. However, 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 and in December 2016, the CFTC further refined and reproposed rules on position limits. Under the reproposed rules, the CFTC would place volumetric limitations on certain positions in 25 core physical commodity futures contracts and their economically equivalent futures, options and swaps. 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. The comment period on the reproposed rules closed on February 28, 2017, and the proposal remains pending.

President Trump and the U.S. Congress have taken various actions suggesting some interest in amending some of the statutory and regulatory provisions impacting financial markets and institutions. The CFTC Chairman and Commissioners have also indicated an interest in reevaluating some of the existing regulations and regulatory proposals. It is not clear at this time what, if any, changes in the law will be enacted or what, if any, changes in the existing regulations will be adopted, or how any such changes would impact our hedging activity. In addition, the President has nominated a new Chairman for the CFTC. (The existing Chairman's term expires in April 2019, although he can stay on for a period of time if his successor has not been confirmed.) It is not clear what, if any, effect a change in leadership at the CFTC would have on consideration of any changes in the existing regulations.

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 unconsolidated affiliates, 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 unconsolidated affiliates 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

Table of Contents

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 unconsolidated affiliates 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.

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

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;

51

Table of Contents

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

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

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

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

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

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

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

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

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

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

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

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

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

The NYSE does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

We currently list our common units on the NYSE under the symbol "EPD." Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our general partner's Board or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE's shareholder approval rules that apply to a corporation. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements. See Part III, Item 10 of this annual report for additional information.

Table of Contents

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 31.9% 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. Unitholders 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 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.

Table of Contents

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 and officers of our general partner with their own choices and to influence the decisions taken by the Board and officers of our general partner.

We do not have the same flexibility as other types of organizations to accumulate cash and issue 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.

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 otherwise subject to a material amount of entity-level taxation, then cash available for distribution to our unitholders would be reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. Despite the fact that we are organized as a limited partnership under Delaware law, we will be treated as a corporation for federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement 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 taxation as an entity. We have not requested, and do not plan to request, a ruling from the Internal Revenue Service ("IRS") with respect to our classification as a partnership for federal income tax purposes.

Table of Contents

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 and we would also likely pay additional state and local income taxes at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions 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 reduced. Thus, treatment of us as a corporation could result in a reduction in the anticipated cash-flow and after-tax return to our unitholders, which would cause a reduction in the value of our common units.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, capital, and other forms of business taxes, as well as subjecting nonresident partners to taxation through the imposition of withholding obligations and composite, combined, group, block, or similar filing obligations on nonresident partners receiving a distributive share of state "sourced" income. We currently own property or do business in a substantial number of states. Imposition on us of any of these taxes in jurisdictions in which we own assets or conduct business or an increase in the existing tax rates could substantially reduce the cash available for distribution to our unitholders.

From 2013 through 2017, several publicly traded partnerships merged into their corporate general partner sponsors. In 2018 and continuing into 2019, the combination of a number of additional factors, including the passage of the Tax Cuts and Jobs Act of 2017 (which lowered the federal corporate tax rate from 35% to 21% and generally provides for the expensing of certain capital expenditures and acquisitions), the FERC issuing its Revised Policy Statement on the Treatment of Income Taxes in March 2018, and, generally, continued lower demand and related liquidity for midstream energy companies (including those structured as publicly traded partnerships) led to additional publicly traded partnerships to either (i) merge into their corporate general partner sponsors, (ii) merge into their general partner structured as a partnership and then elect for the combined entity to be taxed as a corporation, or (iii) voluntarily elect to be taxed as a corporation. These conversions have materially reduced the number of publicly traded partnerships and the total market capitalization and the depth of capital available for the publicly traded partnership sector.

While we currently believe that our classification as a partnership for federal income tax purposes continues to provide a net benefit for our unitholders, should we continue to see (i) additional publicly traded partnerships elect to be taxed as corporations, which could result in a further decrease in the total market capitalization of the publicly traded partnership sector, (ii) lower demand for equity capital in the publicly traded partnership sector, (iii) the absence of a historic premium in the market valuation of publicly traded partnerships compared to midstream energy companies taxed as corporations (or if we see any discount in the valuation of our partnership compared to such companies), or (iv) a combination thereof that results in a material difference in our cost of capital or limits our access to capital, the board of directors of our general partner may determine it is in our unitholders' best interest to change our classification as a partnership for federal income tax purposes. Should the general partner recommend that we change our tax classification, such change would be subject to the approval of our common unitholders.

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. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships or an investment in our common units.

Further, final Treasury Regulations under Section 7704(d)(1)(E) of the Internal Revenue Code recently published in the Federal Register interpret the scope of qualifying income requirements for publicly traded partnerships by providing industry-specific guidance. We do not believe the final Treasury Regulations affect our ability to be treated as a partnership for federal income tax purposes.

Table of Contents

In addition, the Tax Cuts and Jobs Act (the "Tax Act") enacted December 22, 2017, made significant changes to the federal income tax rules applicable to both individuals and entities, including changes to the effective tax rate on an individual or other non-corporate unitholder's allocable share of certain income from a publicly traded partnership. The Tax Act is complex and the Treasury Department and IRS continue to release regulations relating to and interpretive guidance of the legislation contained in the Tax Act. Thus, unitholders should consult their tax advisor regarding the Tax Act and its effect on an investment in our common units.

Any changes to federal income tax laws and interpretations thereof (including administrative guidance relating to the Tax Act) 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 or otherwise adversely affect our business, financial condition or results of operations. Any such changes or interpretations thereof could adversely impact the value of an investment in our common units.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred.

We generally prorate our 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. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, 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 has made no determination as to our status as a partnership for U.S. federal income tax purposes. 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 and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. 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, our costs of any contest with the IRS, principally legal, accounting and related fees, will be indirectly borne by our unitholders because the costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case we would pay the taxes directly to the IRS. If we bear such payment our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Our general partner would cause us to pay the taxes (including any applicable penalties and interest) directly to the IRS. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own common units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced.

Table of Contents

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

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 may be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive any cash distributions from us. Our common unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting from their share of our taxable income.

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

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their 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 taxed as ordinary income due to potential recapture items such as depreciation. 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”) or 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. Additionally, gain recognized by a non-U.S. person on the sale of common units occurring on or after November 27, 2017, will generally be treated as effectively connected income and subject to U.S. federal income tax. Although sales of common units by non-U.S. persons occurring after December 31, 2017, are also subject to withholding taxes under the Tax Act, Notice 2018-08 provides that withholding is not required with respect to such sales until regulations or other guidance has been issued by the IRS. A unitholder that is a tax-exempt entity or a non-U.S. person should consult a tax advisor before investing in our common units.

We treat each purchaser of our common units as having the same tax benefits without regard to the 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.

Table of Contents

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 imposed by the various jurisdictions in which we do business or own property now or in the future, 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, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property or conduct business in a substantial number of states, many of which impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal or corporate income tax. It is the responsibility of each unitholder to file its own federal, state and local tax returns, as applicable.

A unitholder whose common units are the subject of a securities loan (e.g., a loan 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 there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, 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 and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, 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. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from lending their common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our respective assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our respective assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

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

ITEM 1B. UNRESOLVED SEC STAFF COMMENTS.

None.

Table of Contents

ITEM 3. LEGAL PROCEEDINGS.

As part of our normal business activities, we may be named as defendants in 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 fully indemnify us against losses 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 as of the filing date of this annual report to which we are a party, other than routine litigation incidental to our business.

Energy Transfer Matter

In connection with a proposed pipeline project, we and 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 trial court entered judgment against us in an aggregate amount of $535.8 million, which included (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 us against ETP and (iii) prejudgment interest in the amount of $66.4 million. The trial court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5%, compounded annually.

We filed our Brief of the Appellant in the Court of Appeals for the Fifth District of Dallas, Texas on March 30, 2015 and ETP filed its Brief of Appellees on June 29, 2015. We filed our Reply Brief of Appellant on September 18, 2015. Oral argument was conducted on April 20, 2016, and the case was then submitted to the Court of Appeals for its consideration. On July 18, 2017, a panel of the Court of Appeals issued a unanimous opinion reversing the trial court's judgment as to all of ETP's claims against Enterprise, rendering judgment that ETP take nothing on those claims, and affirming Enterprise's counterclaim against ETP of $0.8 million, plus interest.

On August 31, 2017, ETP filed a motion for rehearing before the Dallas Court of Appeals, which was denied on September 13, 2017. On December 27, 2017, ETP filed its Petition for Review with the Supreme Court of Texas and we filed our Response to the Petition for Review on February 26, 2018. On June 8, 2018, the Supreme Court of Texas requested that the parties file briefs on the merits, and the parties have filed their respective submittals. As of December 31, 2018, we have not recorded a provision for this matter as management continues to believe that payment of damages by us in this case is not probable. We continue to monitor developments involving this matter.

PDH Litigation

In July 2013, we executed a contract with Foster Wheeler USA Corporation ("Foster Wheeler") pursuant to which Foster Wheeler was to serve as the general contractor responsible for the engineering, procurement, construction and installation of our PDH facility. In November 2014, Foster Wheeler was acquired by an affiliate of AMEC plc to form Amec Foster Wheeler plc, and Foster Wheeler is now known as Amec Foster Wheeler USA Corporation

(“AFW”). In December 2015, Enterprise and AFW entered into a transition services agreement under which AFW was partially terminated from the PDH project. In December 2015, Enterprise engaged a second contractor, Optimized Process Designs LLC (“OPD”), to complete the construction and installation of the PDH facility.

Table of Contents

On September 2, 2016, we terminated AFW for cause and filed a lawsuit in the 151st Judicial Civil District Court of Harris County, Texas against AFW and its parent company, Amec Foster Wheeler plc, asserting claims for breach of contract, breach of warranty, fraudulent inducement, string-along fraud, gross negligence, professional negligence, negligent misrepresentation and attorneys' fees. We intend to diligently prosecute these claims and seek all direct, consequential, and exemplary damages to which we may be entitled.

Environmental Matters

On occasion, we are assessed monetary penalties by governmental authorities related to administrative or judicial proceedings involving environmental matters. In December 2017, we received a Notice of Enforcement from the Texas Commission on Environmental Quality associated with historical self-disclosed violations that occurred at our Mont Belvieu complex. The eventual resolution of these matters may result in monetary sanctions in excess of $0.1 million. We do not expect such expenditures to be material to our consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

Table of Contents

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, 2019, there were 2,445 unitholders of record of our common units. For information regarding our quarterly cash distributions to partners, see Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Recent Issuance of Unregistered Securities

On April 5, 2018, we issued 1,223,242 common units to an unaffiliated third party in a private placement exempt from the registration requirements of the Securities Act of 1933, as amended (pursuant to Section 4(a)(2) thereof), in connection with our acquisition of land in the Houston, Texas area. The agreement pursuant to which we issued these common units contained customary representations, warranties and covenants, including the certification of facts relating to the availability of the exemption described above.

Other than as described above, there were no issuances of unregistered equity securities during 2018.

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

The following table summarizes our equity repurchase activity during the fourth quarter of 2018:

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Programs	Maximum Number of Units That May Yet Be Purchased Under the Programs
Vesting of phantom unit awards:			--	--
October 2018	--	--	--	--
November 2018 (1)	11,161	$ 26.98	--	--
December 2018	--	--	--	--
Common Unit Buyback Program:				
October 2018	--	--	--	1,236,800
November 2018	--	--	--	1,236,800
December 2018 (2)	1,236,800	$ 24.92	1,236,800	--

(1) Of the 42,290 phantom unit awards that vested in November 2018 and converted to common units, 11,161 units were sold back to us by employees to cover related withholding tax requirements. We cancelled these treasury units

immediately upon acquisition.
(2) In December 1998, we announced a common unit buyback, or repurchase, program whereby we, together with certain affiliates, could repurchase up to 4,000,000 of our common units on the open market. We purchased the remaining authorized amount of 1,236,800 common units in December 2018. We cancelled these treasury units immediately upon acquisition.

In January 2019, we announced that the Board of Enterprise GP had approved a $2.0 billion multi-year unit buyback program, which provides the partnership with an additional method to return capital to investors. The program authorizes the partnership to repurchase its common units from time to time, including through open market purchases and negotiated transactions. The timing and pace of buy backs under the program will be determined by a number of factors including (i) our financial performance and flexibility, (ii) organic growth and acquisition opportunities with higher potential returns on investment, (iii) our unit price and implied distributable cash flow yield and (iv) maintaining targeted financial leverage with a debt-to-normalized EBITDA, or earnings before interest, taxes, depreciation and amortization, ratio in the 3.5 times area. No time limit has been set for completion of the buyback program, and the program may be suspended or discontinued at any time.
61

Table of Contents

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. As presented in the table, amounts are in millions (except per unit data).

	For the Year Ended December 31,				
	2018	2017	2016	2015	2014
Statement of operations data:					
Total revenues	$36,534.2	$29,241.5	$23,022.3	$27,027.9	$47,951.2
Cost of sales	26,789.8	21,487.0	15,710.9	19,612.9	40,464.1
Other costs and expenses	4,815.8	4,251.6	4,092.7	4,248.4	3,970.9
Operating income	5,408.6	3,928.9	3,580.7	3,540.2	3,775.7
Net income	4,238.5	2,855.6	2,553.0	2,558.4	2,833.5
Net income attributable to limited partners	4,172.4	2,799.3	2,513.1	2,521.2	2,787.4
Earnings per unit:					
Basic ($/unit)	1.91	1.30	1.20	1.28	1.51
Diluted ($/unit)	1.91	1.30	1.20	1.26	1.47
Cash distributions per unit with respect to year	1.7250	1.6825	1.6100	1.5300	1.4500

	At December 31,				
	2018	2017	2016	2015	2014
Balance sheet data:					
Property, plant and equipment, net	$38,737.6	$35,620.4	$33,292.5	$32,034.7	$29,881.6
Total assets	56,969.8	54,418.1	52,194.0	48,802.2	47,057.7
Long-term debt, including current maturities	26,178.2	24,568.7	23,697.7	22,540.8	21,220.5
Total liabilities	32,677.6	31,645.7	29,928.0	28,301.1	27,365.5
Total equity	24,292.2	22,772.4	22,266.0	20,501.1	19,692.2
Limited partner units outstanding (millions)	2,184.9	2,161.1	2,117.6	2,012.6	1,937.3

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. For additional information regarding energy commodity prices, see “Selected Energy Commodity Price Data” included under Part II, Item 7 of this annual report. General information regarding our results of operations can also be found under Part II, Item 7 of this annual report.

Our property, plant and equipment amounts increased over the last five years primarily due to investments in growth capital projects. For information regarding our capital investment program, see “Capital Investments” included under Part II, Item 7 of this annual report.

Debt increased over the last five years primarily due to the funding of a portion of our capital investments using borrowings under bank credit agreements and the issuance of short- and long-term notes. For information regarding our debt, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Our equity balances, along with the number of common units outstanding, increased in each of the years presented due to the issuance of units in connection with our at-the-market program, distribution reinvestment plan and employee unit purchase plan. Net proceeds generated from the sale of common units were used to fund a portion of our capital investments.

Table of Contents

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

For the Years Ended December 31, 2018, 2017 and 2016

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 ("U.S.").

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 Directors (the "Board") of Enterprise GP; (ii) Richard H. Bachmann, who is also a director and Vice Chairman of the Board of Enterprise GP; and (iii) Dr. Ralph S. Cunningham, who is also an advisory director of Enterprise GP. Ms. Duncan Williams and Mr. Bachmann also currently serve as managers of Dan Duncan LLC along with W. Randall Fowler, who is also a director and the President and Chief Financial Officer of Enterprise GP.

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. Duncan Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO. Ms. Duncan Williams and Mr. Bachmann also currently serve as directors of EPCO along with Mr. Fowler, who is also the Executive Vice President and Chief Financial Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 31.9% of our limited partner interests at December 31, 2018.

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, 2018 (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," "would," "will," "
"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

Table of Contents

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 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 the 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 export and import terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 49,200 miles of pipelines; 260 MMBbls of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 Bcf of natural gas storage capacity.

The safe operation of our assets is a top priority. 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. For additional information, see "Environmental, Safety and Conservation" within the Regulatory Matters section of Part I, Items 1 and 2 of this annual report.

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. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. 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.

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, and (iv) 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 and expansion 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, a non-generally accepted accounting principle ("non-GAAP") financial measure, for the partnership. The financial results of our marketing efforts fluctuate 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.

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., federal and state regulation, the cost and availability of capital to energy companies to invest in upstream exploration and production activities and the credit quality of our customers. 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 and other matters. For a discussion of the principal effects of such laws and regulations on our business activities, see “Regulatory Matters” included under Part I, Items 1 and 2 of this annual report.

Table of Contents

Significant Recent Developments

Enterprise Begins Service on the Shin Oak NGL Pipeline

In April 2017, we announced plans to build the 658-mile Shin Oak NGL Pipeline to transport growing NGL production from the Permian Basin to our NGL fractionation and storage complex located at the Mont Belvieu hub. The Mont Belvieu area in Chambers County, Texas, with its significant energy-related infrastructure, is a key hub of the global NGL industry (the "Mont Belvieu hub"). In February 2019, the 24-inch diameter mainline segment of the Shin Oak NGL Pipeline from Orla, Texas to Mont Belvieu was placed into limited commercial service with an initial transportation capacity of 250 MBPD. Completion of the related 20-inch diameter Waha lateral is scheduled for the second quarter of 2019. Supported by long-term customer commitments, the Shin Oak NGL Pipeline will ultimately provide up to 550 MBPD of transportation capacity, which is expected to be available in the fourth quarter of 2019.

In May 2018, Apache Corporation ("Apache") executed a long-term supply agreement to sell all of its NGL production from the Alpine High discovery to us. Alpine High is a major hydrocarbon resource located in the Delaware Basin that encompasses rich and dry natural gas and oil-bearing horizons. Apache holds approximately 336,000 net acres in the Alpine High discovery. Enterprise has committed to purchase up to 205 MBPD of NGLs from Apache over the initial ten-year term of the supply agreement, the term of which may be extended at the consent of the parties.

In conjunction with the long-term NGL supply agreement, we granted Apache an option to acquire up to a 33% equity interest in our subsidiary that owns the Shin Oak NGL Pipeline. In November 2018, Apache contributed this option to Altus Midstream Company, which is a majority-owned subsidiary of Apache. The option is exercisable within sixty days after certain completion milestones are met (as defined in the underlying agreements), which we expect to occur in the second quarter of 2019.

Enterprise Announces $2 Billion Unit Buyback Program; Provides 2019 Distribution Guidance

In January 2019, we announced that the Board of Enterprise GP had approved a $2.0 billion multi-year unit buyback program, which provides the partnership with an additional method to return capital to investors. The program authorizes the partnership to repurchase its common units from time to time, including through open market purchases and negotiated transactions. The timing and pace of buy backs under the program will be determined by a number of factors including (i) our financial performance and flexibility, (ii) organic growth and acquisition opportunities with higher potential returns on investment, (iii) our unit price and implied distributable cash flow yield and (iv) maintaining targeted financial leverage with a debt-to-normalized adjusted EBITDA, or earnings before interest, taxes, depreciation and amortization, ratio in the 3.5 times area. No time limit has been set for completion of the buyback program, and the program may be suspended or discontinued at any time.

Also, based on current expectations, management announced its plans to continue to recommend to the Board an increase of $0.0025 per unit per quarter to our cash distribution rate with respect to 2019. The anticipated rate of increase would result in distributions for 2019 (of $1.7650 per unit) being 2.3% higher than those paid for 2018 (of $1.7250 per unit). The payment of any quarterly cash distribution is subject to Board approval and management's evaluation of our financial condition, results of operations and cash flows in connection with such payment.

Service Begins on the Midland-to-ECHO 2 Pipeline System

The Midland-to-ECHO 2 Pipeline System, which began limited commercial service in February 2019, provides us with approximately 200 MBPD of incremental crude oil transportation capacity from the Permian Basin to markets in the Houston area. The pipeline is expected to enter full commercial service in April 2019. The pipeline originates at our Midland terminal and extends 440 miles to our Sealy terminal, with volumes arriving at Sealy transported to our

ECHO terminal using the Rancho II pipeline, which is a component of our South Texas Crude Oil Pipeline System.

We converted a portion of our Seminole NGL Pipeline system from NGL service to crude oil service to create the Midland-to-Sealy segment of this pipeline system. The conversion is supported by a 10.75-year transportation contract with firm demand fees. The conversion does not reduce our NGL transportation capacity since displaced NGLs are transported using our other NGL pipelines, including our Shin Oak NGL Pipeline. Furthermore, we have the ability to convert this pipeline back to NGL service should market and physical takeaway conditions warrant.

Table of Contents

Enterprise Increasing NGL Fractionation Capacity in Texas and Louisiana

The demand for NGL fractionation capacity continues to expand as producers in domestic shale plays like the Permian Basin, Eagle Ford and Denver-Julesburg ("DJ") Basin seek market access and end users require supply assurance. In light of this ongoing trend, we are constructing a new NGL fractionation facility in Chambers County, Texas adjacent to our existing Mont Belvieu NGL fractionation complex. The new facility will consist of two fractionation trains capable of processing a combined 300 MBPD of NGLs. The first of the two fractionation trains will have a nameplate capacity of 150 MBPD and is scheduled to be completed and begin service in the fourth quarter of 2019. The second of these fractionation trains will also have a nameplate capacity of 150 MBPD, and is scheduled to begin service in the first half of 2020.

In November 2018, we announced a project to optimize our Shoup NGL fractionator located in Nueces County, Texas by expanding and repurposing a portion of our South Texas pipelines. This project would entail the construction of approximately 21 miles of new pipeline along with the conversion of approximately 65 miles of existing natural gas pipelines to NGL service, which will allow us to supply Shoup with an additional 25 MBPD of NGL volumes. The expanded pipeline capacity is expected to be available in the third quarter of 2019.

We restarted our Tebone NGL fractionator located in Ascension Parish, Louisiana in February 2019. Tebone has a fractionation capacity of 30 MBPD and is connected by pipeline to each of our Louisiana natural gas processing plants, as well as our Mont Belvieu storage complex. The resumption of service at Tebone complements our operations at the Norco and Promix NGL fractionators and provides us with another processing option for NGLs delivered to the Mont Belvieu hub.

The construction of our new 300 MBPD NGL fractionation facility at our Mont Belvieu NGL fractionation complex, the optimization of our Shoup facility and restart of our Tebone fractionator highlights the flexibility of our integrated midstream network and provides a timely, efficient and cost-effective solution for accommodating growing production from domestic shale basins. Once these projects are fully complete, total NGL fractionation capacity across our network would increase to approximately 1.1 MMBPD in the Mont Belvieu area, and approximately 1.5 MMBPD company-wide.

Enterprise Begins Construction of Seventh Natural Gas Processing Plant in Delaware Basin;
Second Train at Orla Natural Gas Processing Plant Begins Service

In October 2018, we announced that construction of our Mentone cryogenic natural gas processing plant had commenced. The Mentone plant, which is located in Loving County, Texas, is expected to have the capacity to process 300 MMcf/d of natural gas and extract in excess of 40 MBPD of NGLs. The project is scheduled to be completed in the first quarter of 2020 and is supported by a long-term acreage dedication agreement. The Mentone plant further extends our presence in the growing Delaware Basin and provides access to our fully integrated midstream asset network serving domestic and international markets. To support development of the Mentone plant, we are constructing approximately 70 miles of gathering and residue pipelines and expanding compression capabilities. These projects will allow the Mentone plant to link to our NGL system, including the Shin Oak NGL Pipeline which entered limited commercial service in February 2019, as well as our Texas Intrastate System. We will own and operate the Mentone facility and related infrastructure.

The Mentone plant will complement our existing cryogenic natural gas processing plant located near Orla, Texas in Reeves County. In May 2018 and October 2018, we commenced operations of the first and second processing trains (Orla I and Orla II), respectively, at the facility. A third processing train (Orla III) is scheduled to be completed in the second quarter of 2019. We own and operate the Orla facility. In conjunction with the start-up of Orla I, we placed into service approximately 70 miles of natural gas pipelines that connect the Orla facility to our Texas Intrastate

System. We also placed into service a 30-mile extension of our NGL system that provides producers at the Orla facility with NGL takeaway capacity and direct access to our integrated network of downstream NGL assets.

When the Mentone plant is completed and placed into service, we expect to have an aggregate 1.6 Bcf/d of natural gas processing capacity and 250 MBPD of NGL production from our processing plants in the Delaware Basin.

Table of Contents

CME Group Launches Physical West Texas Intermediate (“WTI”) Houston Crude Oil Futures Contract

In September 2018, the CME Group, a leading derivatives marketplace, announced that suppliers, refiners and end users of U.S. crude oil have a new way to price and hedge WTI in Houston, Texas. Participants will have the flexibility to make or take delivery of WTI at our ECHO terminal, Enterprise Hydrocarbons Terminal (“EHT”) or pipeline interconnect at Genoa Junction. The new futures contracts received regulatory approval in October 2018 and are listed with and subject to the rules of the New York Mercantile Exchange (“NYMEX”), beginning with the January 2019 contract month.

Enterprise Expanding LPG Capacity at Houston Ship Channel Terminal

In September 2018, we announced a project to increase LPG loading capacity at EHT by 175 MBPD, or approximately 5 MMBbls per month. The expansion will bring our total LPG export capacity at EHT to 720 MBPD, or approximately 21 MMBbls per month. Upon completion of this expansion project, EHT will have the capability to load up to six Very Large Gas Carrier (“VLGC”) vessels simultaneously, while maintaining the option to switch between loading propane and butane. Once operational, the expansion will allow EHT to load a single VLGC in less than 24 hours, creating greater efficiencies and cost savings for our customers. The incremental loading capacity is expected to be available in the third quarter of 2019.

Enterprise to Develop Offshore Texas Crude Oil Export Terminal

In July 2018, management announced that we are in the planning stage to develop a crude oil export terminal located offshore along the Texas Gulf Coast. The terminal would be capable of fully loading Very Large Crude Carrier (“VLCC”) marine tankers, which have capacities of approximately 2 MMBbls and provide the most efficient and cost-effective solution to export crude oil to the largest international markets in Asia and Europe. We started front-end engineering and design work for the terminal in 2018 and filed our application for regulatory permitting with the Maritime Administration (“MARAD”) in January 2019. Based on initial designs, the project could include pipelines extending from onshore facilities to an offshore terminal loading crude oil for export at approximately 85,000 barrels per hour. A final investment decision for the project will be subject to receiving state and federal permits and customer demand.

Seaway Commences Loading Services for VLCC Tankers

In June 2018, we commenced the loading of VLCC tankers using a combination of our jointly owned Seaway marine terminal located in Texas City, Texas and lightering operations in the Gulf of Mexico. Approximately 1.1 MMBbls of crude oil were loaded onto the FPMC C Melody at the Texas City marine terminal and the remainder of the crude oil shipment was loaded on the VLCC in a lightering zone in the Gulf of Mexico. The FPMC C Melody, chartered by Vitol, Inc., was the first VLCC to be loaded at a Texas port. The Seaway marine terminal features two docks, a 45-foot draft, an overall length of 1,125 feet, a 200-foot beam (width) and the capacity to load crude oil at a rate of 35,000 barrels per hour.

Affiliate of Western Gas Acquires 20% Ownership Interest in Portion of Midland-to-ECHO 1 Pipeline System

In June 2018, an affiliate of Western Gas Partners, LP (“Western”) acquired a noncontrolling 20% equity interest in our subsidiary, Whitethorn Pipeline Company LLC (“Whitethorn”), for $189.6 million in cash. Whitethorn owns the majority of our Midland-to-ECHO 1 Pipeline System, which originates at our Midland terminal and extends 418 miles to our Sealy terminal. Volumes arriving at Sealy are then transported to our ECHO terminal using our Rancho II pipeline. The Midland-to-ECHO 1 Pipeline System provides Permian Basin producers with the ability to transport multiple grades of crude oil, including WTI, Light WTI, West Texas Sour, and condensate, to Gulf Coast markets. As a result of operating enhancements and supplementary infrastructure, the pipeline's transportation capacity is expected to increase to 620 MBPD beginning in March 2019. We report the pipeline's transportation volumes on a net basis that reflects our 80% interest.

Upon closing of the transaction whereby Western acquired its 20% equity interest in Whitethorn, we credited Western for 20% of the pipeline's earnings since it was placed into service in November 2017. We paid Western $45.7 million in June 2018 to settle this obligation.

Table of Contents

Construction Begins on Ethylene Export Dock

In May 2018, we announced that construction of our ethylene export terminal located at Morgan's Point on the Houston Ship Channel had commenced. When completed, the terminal, which we will operate, is expected to have an export capacity of approximately 2.2 billion pounds of ethylene per year, with loading rates of 2.2 million pounds per hour, and feature on-site refrigerated storage for 66 million pounds of ethylene. The project, which is underwritten by long-term customer commitments, is expected to begin limited commercial service in the fourth quarter of 2019, with full operations expected in the fourth quarter of 2020 once certain refrigeration assets are complete. We own a 50% equity interest in Enterprise Navigator Ethylene Terminal LLC, which owns the export terminal.

Enterprise and Energy Transfer form Joint Venture to Restore Service on Old Ocean Pipeline

In May 2018, we announced the formation of a 50/50 joint venture with Energy Transfer Partners, L.P. ("ETP") to resume full service on the Old Ocean natural gas pipeline owned by ETP. The 24-inch diameter Old Ocean Pipeline originates in Maypearl, Texas in Ellis County and extends south approximately 240 miles to Sweeny, Texas in Brazoria County. ETP serves as operator of the pipeline, which has a natural gas transportation capacity of 160 MMcf/d. Repairs were completed on the pipeline and it entered full service in January 2019. In addition, both parties expanded their jointly owned North Texas 36-inch diameter natural gas pipeline, which is a component of our Texas Intrastate System. The expansion project was completed in January 2019 and provides us with additional natural gas takeaway capacity of 150 MMcf/d from West Texas, including deliveries into the Old Ocean Pipeline. The resumption of full service on the Old Ocean Pipeline and expansion of the North Texas Pipeline provide producers with additional takeaway capacity to accommodate growing natural gas production from the Delaware and Midland Basins.

Expansions of our Front Range and Texas Express Pipelines

In May 2018, we conducted open commitment periods to determine shipper interest in expansions of the Front Range Pipeline ("Front Range") and Texas Express Pipeline ("Texas Express"). Given the positive responses we received from shippers, we are proceeding with the expansion projects. We own a 33.3% equity interest in Front Range and a 35% equity interest in Texas Express. We operate both pipelines.

The expansions are designed to facilitate growing production of NGLs from domestic shale basins, including the DJ Basin in Colorado, by providing DJ Basin producers with flow assurance and greater access to the Gulf Coast markets. The expansions are expected to increase the transportation capacity of Front Range and Texas Express by 100 MBPD and 90 MBPD, respectively. We anticipate the expansion projects will be placed into service during the third quarter of 2019.

Acquisition of Remaining 50% Ownership Interest in Delaware Processing

In March 2018, we acquired the remaining 50% member interest in our Delaware Basin Gas Processing LLC ("Delaware Processing") joint venture for $150.6 million in cash, net of $3.9 million of cash held by the former joint venture. Delaware Processing owns a cryogenic natural gas processing facility (our "Waha" gas plant) having a capacity of 150 MMcf/d. The Waha plant is located in Reeves County, Texas and entered service in August 2016. The acquired business serves growing production of NGL-rich natural gas from the Delaware Basin in West Texas and southern New Mexico. For information regarding this acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Enterprise to Expand Butane Isomerization Facility

In January 2018, we announced plans to expand our butane isomerization facility by up to 30 MBPD of incremental capacity. The expansion is supported by long-term agreements to provide butane isomerization, storage and related pipeline services. We currently expect this project to be completed during the fourth quarter of 2021.

Table of Contents

General Outlook for 2019

We provide midstream energy services to producers and consumers of natural gas, NGLs, crude oil, petrochemicals and refined products. Our financial position, results of operations and cash flows are contingent on the supply of and demand for the energy commodities we handle across our integrated midstream energy asset network. The following information presents our views on key midstream energy supply and demand fundamentals as they impact our operations going into 2019.

Supply Side Observations

The upstream energy industry, including major oil companies, continues to shift resources to shale supply basins. We believe that U.S. shale resources provide attractive economic benefits to producers due to their low risk and short lead time production profiles. Domestic shale resources will continue to play a key role in both U.S. and global markets, further supporting that the U.S. is a major oil supplier on par with the Organization of Petroleum Exporting Countries ("OPEC") and Russia.

During most of 2018, international energy commodity markets were supported as demand for crude oil was strong due to expanding global economic activity, while crude oil supplies were viewed as balanced and maintained through a regime of prescriptive supply cuts by OPEC and Russia. As a result crude oil prices improved significantly: WTI averaged $50.86 per barrel in 2017 and rose to $76.41 by early October 2018. Meanwhile, U.S. oil production rose steadily during that period averaging 9.4 MMBPD in 2017 and reached a record 11.8 MMBPD by December 2018. Likewise, U.S. production of NGLs averaged 3.8 MMBPD in 2017 and increased to 4.7 MMBPD by November 2018, a new record as well. U.S. crude oil and NGL production was expected to average 10.9 MMBPD and 4.4 MBPD, respectively, in 2018.

However, beginning in October 2018, signs of weakness began emerging in global energy markets due to perceived overproduction of crude oil and NGLs in the U.S. The impact of trade wars between the U.S., China and other developed economies, along with potential signs of economic slowdown in many developing economies, started eroding confidence in global demand. Also, there was uncertainty regarding how U.S. sanctions on Iran would be administered and their effect on Iranian oil exports. As a result, WTI oil prices tumbled from the high of $76.41 per barrel in early October 2018 to end the year at $45.41 per barrel, a decline of 41%. WTI prices averaged $64.90 per barrel for all of 2018.

In response to the rapid decline in crude oil prices, OPEC and Russia agreed to cut their overall production by 1.2 MMBPD during the first half of 2019, with 800 MBPD shouldered by OPEC and the remainder by Russia and other non-OPEC countries. All in all, OPEC and Russia reduced their production in 2017, 2018 and into 2019 as they adjust to the new reality. The U.S. has now secured its place as a major global oil supplier with production levels that match, if not surpass, Russia and Saudi Arabia. As such, the new imperative for non-U.S. producers is the delicate balancing of U.S., OPEC (primarily Saudi Arabia) and Russian production, while attempting to maintain crude oil prices at a level that ensures production doesn't grow too fast, but not too low as to cause massive fiscal deficits in oil producing nations that could threaten their political stability.

With the growth in domestic shale resources, U.S. natural gas production has increased significantly over the past few years with production estimates of 89 Bcf/d at the end of 2018. As a result, natural gas prices have been suppressed in recent years as a result of strong domestic supplies exceeding demand, particularly for heating needs as recent average winter temperatures have been warmer. As measured by the New York Mercantile Exchange ("NYMEX") at Henry Hub, natural gas prices for 2018 ranged from a high of $4.84 per MMBtu to a low of $2.55 per MMBtu, while averaging $3.07 per MMBtu. We believe that natural gas prices for 2019 will continue in a similar range. Natural gas production should be sufficient to meet both domestic and export demand, regardless of periodic fluctuations in demand and prices attributable to weather events.

U.S. exploration and production companies have shown that they can grow shale production at crude oil prices approximating $50 per barrel and higher. Drilling technology continues to improve, which enables producers to drill and complete non-conventional wells more efficiently. These improvements include faster drilling techniques, longer horizontal well laterals, higher density fracture treatments, and increased proppant concentration. Given that crude oil prices in 2018 were supportive of production growth, rig counts in the U.S. increased 17% during the year to 1,083

69

Table of Contents

at December 31, 2018. However, not all regions have reacted equally to the recovery in rig counts, with the largest increases seen in the Permian Basin (22% increase in 2018) and Eagle Ford Shale (14% increase in 2018).

As more wells were drilled in 2018, most shale basins experienced a shortage of completion equipment and crews, which forced producers to defer completions and build their inventory of drilled but uncompleted wells ("DUCs"). Rig counts plateaued during the second half of 2018, whereas the DUC count increased by 17% during the same period. The DUC count reached approximately 8,600 in December 2018 as reported by the U.S. Energy Information Administration ("EIA"), a 31% increase over the comparable December 2017 amount. More specifically, the Permian basin saw its DUC count increase 77% during 2018 as infrastructure constraints persisted, especially during the third quarter of 2018. The overall increase in DUCs represents a significant potential volume that we believe could be brought into production starting in 2019. We believe that NGL production will benefit disproportionately as these wells are brought online as producers seek greater returns from pursuing rich natural gas at the expense of dry gas wells, and from associated natural gas and NGLs produced in connection with higher crude oil production.

We operate in a number of major supply basins, including the Permian, Eagle Ford Shale, Haynesville Shale and Rockies. The following information represents our outlook for each of these basins:

§ The Permian Basin in West Texas and southeastern New Mexico has experienced the largest increase in drilling activity in the country, with 486 active rigs in December 2018. The basin continues to have many advantages relative to other producing regions, including stacked pay zones, light sweet crude oil and significant infrastructure. Based on producer feedback and forecasts, we believe that there is significant support for the construction of incremental midstream infrastructure in the basin.

An area of focus for us has been the development of midstream infrastructure serving producers in the Delaware Basin, which is part of the overall Permian Basin. Historically, the Delaware Basin has been a relatively lightly drilled area due to a lack of conventional targets. However, with the introduction of horizontal drilling and identification of stacked targets of tight-rock and shales, drilling in the Delaware Basin has accelerated over the past five years. These drilling targets have proven to produce not only crude oil but condensate and NGLs, which present us a significant number of opportunities to provide midstream services to producers. We are actively working with producers to identify those midstream infrastructure projects that will best serve their needs and also complement our integrated asset network.

Two examples of our initiatives in the Delaware Basin are the Orla and Mentone natural gas processing plants. During 2018, we placed two processing trains (Orla I and II) into service at Orla with a third (Orla III) expected to be completed in the second quarter of 2019. Once Orla III is completed, the Orla facility will have 900 MMcf/d of total processing capacity and allow us to extract up to 120 MBPD of mixed NGLs. Our Mentone facility was announced in October 2018 and is scheduled to enter service during the first quarter of 2020. When the Mentone plant is completed and placed into service, we expect to have an aggregate 1.6 Bcf/d of natural gas processing capacity and 250 MBPD of NGL production from our processing plants in the Delaware Basin.

Our Midland-to-ECHO 1 Pipeline System, which became fully operational in the second quarter of 2018, provides Permian Basin producers with the ability to transport multiple grades of crude oil on a segregated basis to Gulf Coast and international markets, thus maintaining and assuring the quality and grade of the final product. As a result of operating enhancements and supplementary infrastructure, the transportation capacity of the Midland-to-ECHO 1 Pipeline System is expected to increase to 620 MBPD beginning in March 2019. In addition, we placed our Midland-to-ECHO 2 Pipeline System into limited commercial service in February 2019, with full service expected in April 2019. The Midland-to-ECHO 2 Pipeline System provides us with approximately 200 MBPD of incremental crude oil transportation capacity from the Permian Basin to markets in the Houston area.

We are also evaluating several other natural gas, NGL and crude oil projects in the Permian Basin.

- Crude oil and natural gas production in the Eagle Ford Shale is increasing due to higher rig counts and improved drilling efficiencies. The number of drilling rigs in the Eagle Ford Shale increased to 81 active rigs in December 2018 compared to a low of 29 rigs during the downturn in 2016. According to the EIA Drilling Productivity Report, the most recent data (December 2018) for production in the Eagle Ford Region was 1.4 MMBPD of crude oil and 7.0 Bcf/d of natural gas.

Table of Contents

Production acreage continues to change ownership in the Eagle Ford Shale, with over 1.5 million acres changing hands in 2018 and we expect this trend to continue. We believe that additional rigs will be brought to the basin as a result of the ownership changes, which could result in higher volumes for our midstream network; however, until volumes for the basin exceed historical peak production, there will likely be excess capacity of midstream infrastructure available in the region. The historical peak for Eagle Ford Region crude oil and natural gas production occurred in March 2015 and was 1.7 MMBPD and 7.4 Bcf/d, respectively. We also believe that the Eagle Ford Shale offers producers some of the best returns on capital of any region in the country due to its proximity to major consumption and export markets along the U.S. Gulf Coast and that midstream companies like us, with deep integrated networks, will enjoy the greatest operating leverage as production increases.

§ Natural gas production in the Haynesville Shale is also increasing due to higher rig counts and improved drilling efficiencies. The number of drilling rigs in the basin has increased from a low of 11 rigs in 2016 to 52 rigs in December 2018. Like the Eagle Ford Shale, we have seen several significant changes in the ownership of producing properties over the past year, which has contributed to increased drilling activity in the region by the new owners. The historical peak for natural gas production in the Haynesville region occurred in 2011 and was over 10.5 Bcf/d. According to the December 2018 EIA Drilling Productivity Report, Haynesville Region natural gas production was 9.8 Bcf/d.

The U.S. Geological Survey estimated in its 2017 assessment that the Haynesville Shale and the associated Bossier shale plays hold a combined 304 trillion cubic feet of technically recoverable shale gas resources, the second highest level in the U.S. after the Appalachia region. The Haynesville Shale benefits from its close proximity to Gulf Coast markets where substantial petrochemical and liquefied natural gas, or LNG, export projects are being constructed. At expected natural gas price levels, we estimate that natural gas production from the Haynesville Shale will continue to increase; however, until volumes for the basin exceed historical peak production, there will likely be excess capacity of midstream infrastructure available in the region.

§ With respect to oil and gas production in the Rocky Mountain region, rig counts have declined slightly in the Jonah and Pinedale fields and are flat in the Piceance and San Juan basins. Producers plan to continue horizontal drilling in the Jonah field; however, horizontal drilling in the Pinedale field has generally been put on hold pending further study. Drilling has continued steadily in the Piceance field, with operators permitting the horizontal Williams Fork locations. Additional resources exist in the Piceance field in the deeper Mancos play, but it is currently not being developed. There were several changes in the ownership of producing properties in the San Juan basin this past year that are expected to lead to a modest increase in drilling activity by the new owners.

The Rockies benefit from sufficient natural gas and NGL pipeline infrastructure, which helps the region compete with other North American regions where production takeaway capacity may be constrained. We believe that our Rocky Mountain assets will continue to benefit regional producers by giving them access to major downstream markets such as the U.S. Gulf Coast and export destinations.

With stable to higher energy commodity prices and continued improvements in drilling and completion technologies, we expect continued strong investments, including both drilling and well completion activities, by producers during 2019 in and around our assets in the Permian Basin, Eagle Ford Shale, Haynesville Shale and Rocky Mountain regions. Furthermore, we believe that our assets in these areas are very competitive in providing midstream services. We also believe that production basins, along with supporting midstream infrastructure such as our integrated network, located closest to prime markets on the U.S. Gulf Coast will continue to be preferred by producers due to more favorable economics as compared to other more distant areas (mostly due to lower transportation costs).

Demand Side Observations

Global economic growth continues to drive increasing demand for petroleum-based products. In December 2018, the International Energy Agency ("IEA") reported that global demand for crude oil and NGLs grew by a combined 1.3 MMBPD in 2018 and expects demand to grow by 1.4 MMBPD in 2019. The IEA anticipates that overall demand for crude oil and NGLs by the countries represented by the Organization for Economic Co-operation and Development ("OECD") would decline by approximately 0.7 MMBPD between 2019 and 2023, while non-OECD demand would increase by 5 MMBPD over the same period. The IEA expects that petrochemicals will account for approximately 40% of the increase in global demand for crude oil and NGLs over this period.

Table of Contents

The North American "shale revolution" has made the U.S. the global, low-cost supplier of NGLs. We expect this trend to continue into 2019 and beyond supported by, among other things, the ability of U.S. shale producers to improve productivity and reduce development costs, higher demand in developing economies for crude oil and related hydrocarbons, and regulatory changes favoring the use of clean-burning fuels and low-sulfur hydrocarbons such as those found in domestic shale oil basins. We continue to foresee a variety of long-term demand-side opportunities from these developments, including higher demand from a resurgent U.S. petrochemical industry and increased exports of hydrocarbons (e.g., ethane, LPG and crude oil) to growing international markets.

With respect to the domestic petrochemical industry, abundant supplies of shale-sourced ethane provides the U.S. with one of the cheapest feedstocks available for ethylene production. The American Chemistry Council estimates that over $200 billion is being invested in domestic chemical production, with most of those investments tied directly to producing ethylene from cost-advantaged U.S. ethane. We believe that domestic demand for ethane is expected to continue growing as several new world-scale ethylene plants begin operations in 2019 and on through the early 2020s. Furthermore, virtually every ethane-consuming chemical plant in the U.S. is in close proximity to our existing assets.

Of the new domestic chemical plants, four are currently operational and have a combined ethylene production capacity of 11.1 billion pounds per year and ethane consumption rate of approximately 310 MBPD. An additional five plants are expected to enter service in 2019, with a combined ethylene production capacity of 10.5 billion pounds per year and an ethane consumption rate of approximately 295 MBPD, and another four in the early 2020s. The plants expected to enter service in the early 2020s are expected to have a combined ethylene production capacity of 10.8 billion pounds per year and an ethane consumption rate of approximately 295 MBPD. We also anticipate demand growth for ethane as a feedstock resulting from modifications made to other existing domestic facilities (e.g., debottlenecking, furnace modifications, etc.). As a result of the expected growth in U.S. ethylene production capacity, we are constructing an ethylene export terminal located at Morgan's Point on the Houston Ship Channel. The project, which is underwritten by long-term customer commitments, is expected to begin limited commercial service in the fourth quarter of 2019, with full operations expected in the fourth quarter of 2020 once certain refrigeration assets are complete.

International demand for U.S. ethane is expected to remain robust in 2019, as ethane from domestic shale basins also offers the global petrochemical industry a low-cost feedstock option plus supply diversification. Our Morgan's Point Ethane Export Terminal, the largest of its kind in the world, enables us to meet this demand and has an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour of fully refrigerated ethane.

Ethane prices were volatile in 2018 primarily due to supply and demand imbalances attributable to infrastructure gaps (e.g., NGL pipeline and fractionation capacity constraints). We, along with others in the midstream industry, are actively working to resolve these constraints. Overall, the industry expects to place over 1.8 MMBPD of pipeline capacity and 1.7 MMBPD of fractionation capacity into service between 2019 through 2021. However, due to uncertainty regarding the exact start-up dates for several ethane-oriented petrochemical plants, additional volatility in ethane prices cannot be ruled out in 2019.

We believe that U.S. exports of LPG to Asia, particularly China and India, and markets in Northwest Europe and Central and South America will continue to be strong. Per the EIA, U.S. LPG exports increased 9% in 2018 to 1,147 MBPD, based on data available through November 2018, with volumes headed to Asian markets accounting for approximately 50% of this amount (substantially all of which originated from our marine terminals). Our outlook for LPG exports to Asia is supported by a number of factors including: (i) continued economic expansion in emerging Asian markets; (ii) the widening of the Panama Canal, which was completed in 2016; and (iii) favorable domestic policies in countries like India and Indonesia where the governments are subsidizing the switch to LPG for domestic use as a means for reducing pollution and protecting against deforestation. Due to our expectation of continued growth in LPG exports, we announced a project to increase LPG loading capacity at EHT by 175 MBPD, or approximately 5 MMBbls per month. The incremental LPG loading capacity at EHT is expected to be available in the third quarter of 2019.

Table of Contents

Finally, as crude oil production in the U.S. has increased, these new domestic barrels continue to supplant more of the U.S.'s crude oil imports, while the remainder is exported to international markets in Central and South America, Asia and Western Europe where the lighter U.S. crudes are used as feedstock in their refining facilities. We also expect U.S. refiners to continue to operate at high rates as a result of steady U.S. demand and growing exports of refined products. We believe that our marine terminals and related storage and pipeline infrastructure that handle crude oil and refined products are strategically located to meet the concurrent needs of export and import customers. We have significant export capabilities on the Houston Ship Channel at EHT and at Beaumont, Freeport and Texas City, Texas.

Selected Energy Commodity Price Data

The following table presents selected index prices for natural gas 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 (2)	Natural Gasoline, $/gallon (2)	Polymer Grade Propylene, $/pound (3)	Refinery Grade Propylene, $/pound (3)
2016 Averages	$ 2.46	$ 0.20	$ 0.48	$ 0.65	$ 0.68	$ 0.94	$ 0.34	$ 0.21
2017 by quarter:								
1st Quarter	$ 3.32	$ 0.23	$ 0.71	$ 0.98	$ 0.94	$ 1.10	$ 0.47	$ 0.32
2nd Quarter	$ 3.19	$ 0.25	$ 0.63	$ 0.76	$ 0.75	$ 1.07	$ 0.41	$ 0.28
3rd Quarter	$ 2.99	$ 0.26	$ 0.77	$ 0.91	$ 0.92	$ 1.10	$ 0.42	$ 0.28
4th Quarter	$ 2.93	$ 0.25	$ 0.96	$ 1.04	$ 1.04	$ 1.32	$ 0.49	$ 0.35
2017 Averages	$ 3.11	$ 0.25	$ 0.77	$ 0.92	$ 0.91	$ 1.15	$ 0.45	$ 0.31
2018 by quarter:								
1st Quarter	$ 3.01	$ 0.25	$ 0.85	$ 0.96	$ 1.00	$ 1.41	$ 0.53	$ 0.33
2nd Quarter	$ 2.80	$ 0.29	$ 0.87	$ 1.00	$ 1.20	$ 1.53	$ 0.52	$ 0.37
3rd Quarter	$ 2.91	$ 0.43	$ 0.99	$ 1.21	$ 1.25	$ 1.54	$ 0.60	$ 0.45
4th Quarter	$ 3.65	$ 0.35	$ 0.79	$ 0.91	$ 0.94	$ 1.22	$ 0.51	$ 0.35
2018 Averages	$ 3.09	$ 0.33	$ 0.88	$ 1.02	$ 1.10	$ 1.43	$ 0.54	$ 0.38

(1) Natural gas prices are based on Henry-Hub Inside FERC commercial index prices as reported by Platts, which is a division of McGraw Hill Financial, Inc.
(2) NGL prices for ethane, propane, normal butane, isobutane and natural gasoline are based on Mont Belvieu Non-TET commercial index prices as reported by Oil Price Information Service.
(3) Polymer grade propylene prices represent average contract pricing for such product as reported by IHS Chemical, a division of IHS Inc. ("IHS Chemical"). Refinery grade propylene prices represent weighted-average spot prices for such product as reported by IHS Chemical.

Table of Contents

The following table presents selected average index prices for crude oil for the periods indicated:

	WTI Crude Oil, $/barrel (1)	Midland Crude Oil, $/barrel (2)	Houston Crude Oil $/barrel (2)	LLS Crude Oil, $/barrel (3)
2016 Averages	$ 43.32	$ 43.25	$ 44.74	$ 44.88
2017 by quarter:				
1st Quarter	$ 51.91	$ 51.72	$ 53.27	$ 53.52
2nd Quarter	$ 48.28	$ 47.29	$ 49.77	$ 50.31
3rd Quarter	$ 48.20	$ 47.37	$ 50.84	$ 51.62
4th Quarter	$ 55.40	$ 55.47	$ 59.84	$ 61.07
2017 Averages	$ 50.95	$ 50.44	$ 53.41	$ 54.13
2018 by quarter:				
1st Quarter	$ 62.87	$ 62.51	$ 65.47	$ 65.79
2nd Quarter	$ 67.88	$ 59.93	$ 72.38	$ 72.97
3rd Quarter	$ 69.50	$ 55.28	$ 73.67	$ 74.28
4th Quarter	$ 58.81	$ 53.64	$ 66.34	$ 66.20
2018 Averages	$ 64.77	$ 57.84	$ 69.47	$ 69.81

(1) WTI prices are based on commercial index prices at Cushing, Oklahoma as measured by the NYMEX.
(2) Midland and Houston crude oil prices are based on commercial index prices as reported by Argus.
(3) Light Louisiana Sweet (“LLS”) prices are based on commercial index prices as reported by Platts.

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. The weighted-average indicative market price for NGLs was $0.82 per gallon in 2018 compared to $0.69 per gallon in 2017 and $0.50 per gallon in 2016.

An increase in our consolidated marketing revenues due to higher energy commodity sales prices may not result in an increase in gross operating margin or cash available for distribution, since our consolidated cost of sales amounts would also be higher due to comparable increases in the purchase prices of the underlying energy commodities. The same relationship would be true in the case of lower energy commodity sales prices and purchase costs.

We attempt to mitigate commodity price exposure through our hedging activities and the use of fee-based arrangements. See Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding our commodity hedging activities.

Table of Contents

Income Statement Highlights

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

	For the Year Ended December 31,		
	2018	2017	2016
Revenues	$36,534.2	$29,241.5	$23,022.3
Costs and expenses:			
Operating costs and expenses:			
Cost of sales	26,789.8	21,487.0	15,710.9
Other operating costs and expenses	2,898.7	2,500.1	2,425.6
Depreciation, amortization and accretion expenses	1,687.0	1,531.3	1,456.7
Net gains attributable to asset sales	(28.7)	(10.7)	(2.5)
Asset impairment and related charges	50.5	49.8	52.8
Total operating costs and expenses	31,397.3	25,557.5	19,643.5
General and administrative costs	208.3	181.1	160.1
Total costs and expenses	31,605.6	25,738.6	19,803.6
Equity in income of unconsolidated affiliates	480.0	426.0	362.0
Operating income	5,408.6	3,928.9	3,580.7
Interest expense	(1,096.7)	(984.6)	(982.6)
Change in fair value of Liquidity Option Agreement	(56.1)	(64.3)	(24.5)
Other, net	43.0	1.3	2.8
Provision for income taxes	(60.3)	(25.7)	(23.4)
Net income	4,238.5	2,855.6	2,553.0
Net income attributable to noncontrolling interests	(66.1)	(56.3)	(39.9)
Net income attributable to limited partners	$4,172.4	$2,799.3	$2,513.1

Revenues

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

	For the Year Ended December 31,		
	2018	2017	2016
NGL Pipelines & Services:			
Sales of NGLs and related products	$12,920.9	$10,521.3	$8,380.5
Midstream services	2,728.0	1,946.7	1,862.0
Total	15,648.9	12,468.0	10,242.5
Crude Oil Pipelines & Services:			
Sales of crude oil	10,001.2	7,365.2	5,802.5
Midstream services	1,041.4	791.6	712.5
Total	11,042.6	8,156.8	6,515.0
Natural Gas Pipelines & Services:			
Sales of natural gas	2,411.7	2,238.5	1,591.9
Midstream services	1,042.7	907.1	951.1
Total	3,454.4	3,145.6	2,543.0
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	5,535.4	4,696.3	2,921.9

Midstream services	852.9	774.8	799.9
Total	6,388.3	5,471.1	3,721.8
Total revenues	$36,534.2	$29,241.5	$23,022.3

For periods through December 31, 2017, we accounted for our revenue streams using Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 605, Revenue Recognition. Effective January 1, 2018, we adopted FASB ASC 606, Revenue from Contracts with Customers, using a modified retrospective approach that applied the new revenue recognition standard to existing contracts at the implementation date and any future revenue contracts.

For additional information regarding our consolidated revenues, including the adoption of ASC 606, see Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Table of Contents

Comparison of 2018 with 2017
Total revenues for 2018 increased $7.29 billion when compared to 2017 primarily due to a $6.05 billion increase in marketing revenues. Revenues from the marketing of crude oil increased $2.64 billion year-to-year primarily due to higher sales prices, which accounted for a $1.99 billion increase, and higher sales volumes, which accounted for an additional $646.3 million increase. Revenues from the marketing of NGLs, petrochemicals and refined products increased a net $3.24 billion year-to-year primarily due to higher sales prices, which accounted for a $3.39 billion increase, partially offset by a $149.2 million decrease due to lower sales volumes.

Revenues from midstream services for 2018 increased $1.24 billion when compared to 2017. As a result of adopting ASC 606, we recognized $621.7 million in connection with the receipt of non-cash consideration for providing natural gas processing services during 2018. Midstream service revenues from our pipeline assets increased $481.4 million year-to-year primarily due to strong demand for transportation services in Texas and on the ATEX Pipeline.

Comparison of 2017 with 2016
Total revenues for 2017 increased $6.22 billion when compared to total revenues for 2016. Revenues from the marketing of crude oil, natural gas, petrochemicals, refined products and octane additives increased $3.98 billion year-to-year primarily due to higher sales prices, which accounted for a $2.75 billion increase, and higher sales volumes, which accounted for an additional $1.23 billion increase. Revenues from the marketing of NGLs increased $2.14 billion year-to-year primarily due to higher sales prices, which accounted for a $3.19 billion increase, partially offset by a $1.05 billion decrease due to lower sales volumes.

Revenues from midstream services increased $94.7 million year-to-year primarily due to the ongoing expansion of our operations, including a $54.6 million increase attributable to our Morgan's Point Ethane Export Terminal that was placed into service in September 2016.

Largest 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 2018, 2017 and 2016 was Vitol Holding B.V. and its affiliates (collectively, "Vitol"), which accounted for 7.8%, 11.2% and 9.9%, respectively, of our consolidated revenues. Vitol is a global energy and commodity trading company.

Operating costs and expenses

Comparison of 2018 with 2017
Total operating costs and expenses for 2018 increased $5.84 billion when compared to 2017 primarily due to a $5.3 billion increase in cost of sales. The cost of sales associated with our marketing of crude oil increased $2.16 billion year-to-year primarily due to higher purchase prices, which accounted for a $1.59 billion increase, and higher sales volumes, which accounted for an additional $562.4 million increase. The cost of sales associated with our NGL marketing activities increased $3.09 billion year-to-year primarily due to higher sales prices, which accounted for a $2.51 billion increase. In addition, the cost of sales attributable to our NGL marketing activities for 2018 includes $621.7 million resulting from the adoption of ASC 606 and attributable to the sale and delivery of equity NGL products to customers.

Other operating costs and expenses for 2018 increased $398.6 million when compared to 2017 primarily due to higher maintenance, power and employee compensation costs. Depreciation, amortization and accretion expense increased $155.7 million year-to-year primarily due to assets we constructed and placed into service since 2017. Gains related to the sale of assets increased $18.0 million year-to-year primarily due to the sale of our Red River System in October 2018. Operating costs and expenses also include $50.5 million and $49.8 million of non-cash asset impairment and related charges for the years ended December 31, 2018 and 2017, respectively. See Note 14 of the Notes to

Consolidated Financial Statements included under Part II, Item 8 of this annual report for information regarding our nonrecurring fair value measurements.

Table of Contents

Comparison of 2017 with 2016

Total operating costs and expenses for 2017 increased $5.91 billion when compared to total operating costs and expenses for 2016. The cost of sales associated with our marketing of crude oil, natural gas, petrochemicals and refined products increased $3.59 billion year-to-year primarily due to higher purchase prices, which accounted for a $2.52 billion increase, and higher sales volumes, which accounted for an additional $1.06 billion increase. The cost of sales associated with our marketing of NGLs increased a net $2.19 billion year-to-year primarily due to higher purchase prices, which accounted for a $3.06 billion increase, partially offset by an $873.9 million decrease due to lower sales volumes.

Other operating costs and expenses for 2017 increased a net $74.5 million when compared to 2016 primarily due to higher employee compensation, power, ad valorem tax and maintenance costs. Depreciation, amortization and accretion expense in operating costs and expenses for 2017 increased a net $74.6 million when compared to 2016 primarily due to assets we constructed and placed into service since 2016. Operating costs and expenses also include $49.8 million and $52.8 million of non-cash asset impairment and related charges for the years ended December 31, 2017 and 2016, respectively.

General and administrative costs

General and administrative costs for 2018 increased $27.2 million when compared to 2017 primarily due to higher employee compensation and legal costs. General and administrative costs for 2017 increased $21.0 million when compared to 2016 primarily due to higher legal, regulatory and employee compensation costs.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates for 2018 increased $54.0 million when compared to 2017 primarily due to an increase in earnings from our investments in NGL pipelines. Equity income from our unconsolidated affiliates for 2017 increased a net $64.0 million when compared to 2016 primarily due to an increase in earnings from our investments in crude oil pipeline ventures.

Operating income

Operating income for 2018 increased $1.48 billion when compared 2017 due to the previously described year-to-year changes in revenues, operating costs and expenses, general and administrative costs and equity in income of unconsolidated affiliates. Likewise, operating income for 2017 increased $348.2 million when compared to 2016.

Interest expense

The following table presents the components of our consolidated interest expense for the years indicated (dollars in millions):

	For the Year Ended December 31		
	2018	2017	2016
Interest charged on debt principal outstanding	$1,195.4	$1,110.4	$1,088.9
Impact of interest rate hedging program, including related amortization (1)	8.1	38.2	30.5
Interest costs capitalized in connection with construction projects (2)	(147.9)	(192.1)	(168.2)
Other (3)	41.1	28.1	31.4
Total interest expense	$1,096.7	$984.6	$982.6

(1) Amount presented for 2018 is net of $29.4 million of swaption premium income, which reduces interest expense.
(2) We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. Capitalized interest amounts become part of the historical cost of an asset and are charged to earnings (as a component of depreciation expense) on a straight-line basis over the estimated useful life of the asset once the asset enters its intended service. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise. Capitalized interest amounts fluctuate based on the timing of when projects are placed into service, our capital investment levels and the interest rates charged on borrowings.
(3) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization and write-off of debt issuance costs. Amount presented for 2018 includes $14.2 million of debt issuance costs that were written off in connection with the redemption of junior subordinated notes.

Table of Contents

Comparison of 2018 with 2017

Interest expense for 2018 increased $112.1 million when compared to 2017. Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $85.0 million year-to-year primarily due to increased debt principal amounts outstanding during 2018, which accounted for an $85.6 million increase. Our weighted-average debt principal balance for 2018 was $25.94 billion compared to $24.13 billion for 2017. In general, our debt principal balances have increased over time due to the partial debt financing of our capital investments. For a discussion of our consolidated debt obligations and capital investments, see “Liquidity and Capital Resources” and “Capital Investments,” respectively, within this Part II, Item 7 of this annual report.

Comparison of 2017 with 2016

Interest expense for 2017 increased $2.0 million when compared to 2016. Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $21.5 million year-to-year primarily due to increased debt principal amounts outstanding during 2017, which accounted for a $31.6 million increase, partially offset by the effect of lower overall interest rates in 2017, which accounted for a $10.1 million decrease. Our weighted-average debt principal balance for 2017 was $24.13 billion compared to $23.41 billion for 2016.

Change in fair value of Liquidity Option Agreement

We recognize non-cash expense associated with accretion and changes in management estimates that affect our valuation of the Liquidity Option Agreement. For information regarding the Liquidity Option Agreement, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Comparison of 2018 with 2017

Liquidity option expense decreased $8.2 million in 2018 when compared to 2017 due to the effect of changes in management estimates, which accounted for a $13.6 million decrease, partially offset by accretion expense, which accounted for a $5.4 million increase.

Comparison of 2017 with 2016

Liquidity option expense increased $39.8 million in 2017 when compared to 2016 also due to the effect of changes in management estimates, which accounted for a $37.6 million increase, and accretion expense, which accounted for an additional $2.2 million increase. The unfavorable adjustment attributable to changes in management estimates was due to revising the valuation model to reflect applicable provisions of the Tax Cuts and Jobs Act of 2017 (i.e., the limitation of interest expense deductibility, partially offset by a lower federal corporate tax rate).

Gain on step acquisition of unconsolidated affiliate

We recognized a non-cash gain of $39.4 million during 2018 related to the step acquisition of Delaware Processing. For information regarding this acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Income taxes

Provision for income taxes primarily reflects our state tax obligations under the Revised Texas Franchise Tax (the “Texas Margin Tax”). We are not subject to federal income tax. Our provision for income taxes for 2018 increased $34.6 million when compared to 2017 primarily due to increases in taxable margin and the Texas apportionment factor. Our provision for income taxes for 2017 increased $2.3 million when compared to 2016.

Business Segment Highlights

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results.

Table of Contents

The following table presents gross operating margin by segment and non-GAAP total gross operating margin for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2018	2017	2016
Gross operating margin by segment:			
NGL Pipelines & Services	$3,830.7	$3,258.3	$2,990.6
Crude Oil Pipelines & Services	1,511.3	987.2	854.6
Natural Gas Pipelines & Services	891.2	714.5	734.9
Petrochemical & Refined Products Services	1,057.8	714.6	650.6
Total segment gross operating margin (1)	7,291.0	5,674.6	5,230.7
Net adjustment for shipper make-up rights	34.7	5.8	17.1
Total gross operating margin (non-GAAP)	$7,325.7	$5,680.4	$5,247.8

(1) Within the context of this table, total segment gross operating margin represents a subtotal and corresponds to measures similarly titled within our business segment disclosures found under Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Total gross operating margin includes equity in the earnings of unconsolidated affiliates, but is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Total gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests. Our calculation of gross operating margin may or may not be comparable to similarly titled measures used by other companies. Segment gross operating margin for NGL Pipelines & Services and Crude Oil Pipelines & Services reflect adjustments for shipper make-up rights that are included in management's evaluation of segment results. However, these adjustments are excluded from non-GAAP total gross operating margin.

The GAAP financial measure most directly comparable to total gross operating margin is operating income. For a discussion of operating income and its components, see the previous section titled "Consolidated Income Statement Highlights" within this Part II, Item 7. The following table presents a reconciliation of operating income to total gross operating margin for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2018	2017	2016
Operating income (GAAP)	$5,408.6	$3,928.9	$3,580.7
Adjustments to reconcile operating income to total gross operating margin:			
Add depreciation, amortization and accretion expense in operating costs and expenses	1,687.0	1,531.3	1,456.7
Add asset impairment and related charges in operating costs and expenses	50.5	49.8	52.8
Subtract net gains attributable to asset sales in operating costs and expenses	(28.7)	(10.7)	(2.5)
Add general and administrative costs	208.3	181.1	160.1
Total gross operating margin (non-GAAP)	$7,325.7	$5,680.4	$5,247.8

Each of our business segments benefits from the supporting role of our marketing activities. The main purpose of our marketing activities is to support the utilization and expansion 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 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.

Estimated Impact of Hurricane Harvey on Results for 2017

The Gulf Coast region of Texas, including its critical energy infrastructure, was impacted by the cumulative effects of Hurricane Harvey during the third quarter of 2017. Impacts on the energy industry included, but were not limited to, severe flooding and limited access to facilities, disruptions to energy demand from area refineries and petrochemical facilities and the closure of all ports on the Texas Gulf Coast, which limited access to export markets. Although operating at reduced rates, many of our plant, pipeline and storage assets along the Texas Gulf Coast remained operational during the storm.

Table of Contents

We estimate that Hurricane Harvey reduced our gross operating margin for 2017 by $46 million. Of this amount, $30 million represents the combined net impact of lower-than-anticipated volumes and lost business opportunities. The remaining $16 million represents expenses we incurred in connection with hurricane-related repair and recovery costs. The following table summarizes the estimated reduction in gross operating margin by business segment for 2017 due to the hurricane (dollars in millions):

Reduction in total gross operating margin by segment:	
Petrochemical & Refined Products Services	$30.9
NGL Pipelines & Services	8.1
Crude Oil Pipelines & Services	6.0
Natural Gas Pipelines & Services	1.0
Total estimated reduction due to the effects of Hurricane Harvey	$46.0

NGL Pipelines & Services

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

	For the Year Ended December 31,		
	2018	2017	2016
Segment gross operating margin:			
Natural gas processing and related NGL marketing activities	$1,240.1	$911.2	$846.6
NGL pipelines, storage and terminals	2,048.3	1,821.0	1,625.4
NGL fractionation	542.3	526.1	518.6
Total	$3,830.7	$3,258.3	$2,990.6
Selected volumetric data:			
NGL pipeline transportation volumes (MBPD)	3,461	3,168	2,965
NGL marine terminal volumes (MBPD)	593	516	436
NGL fractionation volumes (MBPD)	945	831	828
Equity NGL production (MBPD) (1)	155	158	141
Fee-based natural gas processing (MMcf/d) (2)	4,831	4,572	4,736

(1) Represents the NGL volumes we earn and take title to in connection with our processing activities.
(2) Volumes reported correspond to the revenue streams earned by our natural gas processing plants.

Natural gas processing and related NGL marketing activities
Comparison of 2018 with 2017. Gross operating margin from natural gas processing and related NGL marketing activities for 2018 increased a net $328.9 million when compared to 2017. Gross operating margin from our Meeker, Pioneer and Chaco natural gas processing plants increased $135.4 million year-to-year primarily due to higher average processing margins, including the impact of our related hedging activities. On a combined net basis for these plants, fee-based natural gas processing volumes and equity NGL production increased 126 MMcf/d and decreased 6 MBPD, respectively, year-to-year.

Gross operating margin from our South Texas natural gas processing plants increased a net $71.1 million year-to-year primarily due to higher average processing margins, including the impact of related hedging activities. Fee-based natural gas processing volumes for our South Texas gas plants decreased 130 MMcf/d year-to-year. Gross operating margin from our Permian Basin natural gas processing plants increased a combined $60.8 million year-to-year primarily due to gross operating margin from our Orla gas plant, which commenced operations in May 2018 and generated $41.7 million of the increase, and our acquisition in March 2018 of the remaining 50% ownership interest in our Waha gas plant, which resulted in an incremental $27.9 million of gross operating margin from this plant following the acquisition date. Fee-based natural gas processing volumes and equity NGL production from our Permian Basin natural gas processing plants increased a combined net 273 MMcf/d and 5 MBPD, respectively, year-to-year. Of these amounts, fee-based natural gas processing volumes and equity NGL production at Orla represented 195 MMcf/d and 5 MBPD, respectively.

On a combined basis, gross operating margin from our natural gas processing plants in Louisiana and Mississippi decreased a net $11.7 million year-to-year primarily due to a one-time $19.1 million benefit recorded in the fourth quarter of 2017 in connection with proceeds from a business interruption insurance claim at our Pascagoula gas plant, partially offset by higher combined equity NGL production volumes of 7 MBPD, which accounted for an $11.3 million increase. The Pascagoula gas plant experienced a fire in June 2016 and several months of resulting downtime. The plant was repaired and placed back into commercial service in December 2016.

Gross operating margin from our NGL marketing activities increased a net $73.4 million year-to-year primarily due to higher average sales margins, which accounted for a $236.7 million increase, partially offset by a $164.2 million decrease due to lower sales volumes. As noted previously, the main purpose of our marketing activities in each business segment is to support the utilization and expansion of assets across our midstream energy asset network. Results from marketing strategies that optimize our transportation and plant assets increased $172.3 million and $28.9 million, respectively, year-to-year, partially offset by decreases in earnings related to the optimization of our storage and export assets, which accounted for $99.4 million and $48.7 million, respectively, of decreases year-to-year. In addition, gross operating margin from NGL marketing activities reflects $9.3 million of non-cash, mark-to-market gains for 2018 compared to non-cash, mark-to-market losses of $11.0 million for 2017.

Comparison of 2017 with 2016. Gross operating margin from natural gas processing and related NGL marketing activities for 2017 increased a net $64.6 million when compared to 2016.

Gross operating margin from our natural gas processing plants in Louisiana and Mississippi increased a combined $54.1 million year-to-year primarily due to (i) lower repair and operating costs, which accounted for $19.4 million of the increase and were mainly attributable to fire-related repairs completed at the Pascagoula plant in 2016, (ii) a one-time $19.1 million benefit recorded in the fourth quarter of 2017 in connection with proceeds from the business interruption insurance claim at our Pascagoula gas plant and (iii) higher average processing margins, which accounted for an additional $9.8 million increase. Fee-based natural gas processing volumes at our Louisiana and Mississippi plants increased a combined 138 MMcf/d year-to-year.

Gross operating margin from our Meeker, Pioneer and Chaco natural gas processing plants increased a net $31.5 million year-to-year primarily due to higher average processing margins, which accounted for $41.9 million of the increase and reflect the impact of hedging activities, partially offset by lower average processing fees, which accounted for a $7.3 million decrease. On a combined basis for these three plants, fee-based natural gas processing volumes and equity NGL production decreased 61 MMcf/d and increased 16 MBPD, respectively, year-to-year.

Gross operating margin from our NGL marketing activities decreased a net $10.4 million year-to-year primarily due to lower average sales margins, which accounted for a $37.9 million decrease, partially offset by higher sales volumes, which accounted for a $20.1 million increase, and lower railcar leasing costs, which accounted for an additional $7.4 million increase. Results from NGL marketing’s activities decreased $11.4 million year-to-year due to non-cash, mark-to-market activity.

Gross operating margin from our natural gas processing plants in South Texas decreased a net $9.9 million year-to-year primarily due to lower fee-based processing volumes, which accounted for a $21.7 million decrease, higher maintenance costs, which accounted for an additional $7.3 million decrease, partially offset by higher average processing margins, which accounted for an $18.6 million increase including the impact of hedging activities. Lower producer drilling activity in South Texas in 2017 contributed to a 352 MMcf/d decrease in fee-based natural gas processing volumes for these plants.

Gross operating margin from our Permian Basin natural gas processing plants increased $2.0 million year-to-year, primarily due to gross operating margin from our South Eddy gas plant, which commenced operations in May 2016 and generated $3.9 million of the increase. Fee-based natural gas processing volumes and equity NGL production for our Permian Basin natural gas processing plants increased a combined 73 MMcf/d and 3 MBPD, respectively, year-to-year.

NGL pipelines, storage and terminals
Comparison of 2018 with 2017. Gross operating margin from NGL pipelines, storage and terminal assets for 2018 increased a net $227.3 million when compared to 2017.
81

Table of Contents

Gross operating margin from our Seminole, Chaparral and affiliated NGL pipelines increased a combined net $77.9 million year-to-year primarily due to higher transportation volumes of 123 MBPD, which accounted for a $72.7 million increase, and higher average transportation fees, which accounted for an additional $46.0 million increase, partially offset by higher pipeline offloading and capacity reservation costs paid to our other pipelines of $31.5 million. Gross operating margin from our Mid-America Pipeline System and related terminals increased a net $9.1 million primarily due to (i) higher transportation volumes of 50 MBPD, which accounted for a $26.8 million increase, (ii) higher blending, terminal and offloading revenues, which accounted for a $13.5 million increase, partially offset by (iii) lower average transportation fees, which accounted for an $18.5 million decrease, and (iv) higher pipeline offloading costs paid to affiliate pipelines, which accounted for an additional $16.3 million decrease. Gross operating margin from our equity investment in the Texas Express Pipeline increased $15.0 million year-to-year primarily due to higher transportation volumes of 15 MBPD (net to our interest) in 2018 attributable to contractual increases in committed shipper volumes and volumes offloaded from affiliate pipelines. Due to pipeline infrastructure constraints in the Permian Basin region, we have been using offloading arrangements to optimize available capacity on the Mid-American Pipeline System, Seminole Pipeline and Texas Express Pipelines to transport NGLs to our Mont Belvieu complex.

Gross operating margin from our Appalachia-to-Texas Express, or “ATEX,” pipeline increased $45.6 million year-to-year primarily due to contractual increases in committed shipper volumes. NGL transportation volumes on ATEX increased 22 MBPD year-to-year.

Gross operating margin from our underground storage facilities at the Mont Belvieu hub and in south Louisiana increased a combined $43.0 million year-to-year primarily due to higher storage fees. Gross operating margin from our Morgan’s Point Ethane Export Terminal increased $31.6 million year-to-year primarily due to higher loading volumes of 56 MBPD. Likewise, gross operating margin from our Houston Ship Channel Pipeline System increased $8.6 million year-to-year primarily due to higher transportation volumes, which accounted for $15.7 million of the increase, partially offset by higher maintenance and other operating costs, which accounted for a $7.1 million decrease. Transportation volumes along our Houston Ship Channel Pipeline System increased 84 MBPD, which in turn is attributable to shipments of ethane from Mont Belvieu to the Morgan’s Point export terminal.

Gross operating margin from our Dixie Pipeline and related terminals decreased $10.6 million year-to-year primarily due to higher costs attributable to periodic pipeline integrity testing.

Comparison of 2017 with 2016. Gross operating margin from NGL pipelines, storage and terminal assets for 2017 increased a net $195.6 million when compared to 2016. Gross operating margin from ATEX increased $57.2 million year-to-year primarily due to higher walk-up shipper volumes and contractual increases in committed shipper volumes. NGL transportation volumes for ATEX increased 18 MBPD year-to-year.

Gross operating margin from our Morgan’s Point Ethane Export Terminal and Houston Ship Channel Pipeline System increased a combined $52.9 million year-to-year primarily due to higher volumes. Ethane loading volumes at our Morgan’s Point Ethane Export Terminal, which was placed into service in September 2016, increased 75 MBPD year-to-year. In addition, transportation volumes on our Houston Ship Channel Pipeline System increased 105 MBPD year-to-year primarily due to shipments of ethane from Mont Belvieu to the Morgan’s Point export terminal.

Gross operating margin from our underground storage facility at the Mont Belvieu hub for NGLs and related products increased $50.7 million year-to-year primarily due to higher average storage fees in 2017.

Gross operating margin from our Seminole, Chaparral and affiliated NGL pipelines increased a combined net $23.1 million year-to-year primarily due to higher average transportation fees, which accounted for a $15.9 million increase, and higher transportation volumes, which accounted for an additional $14.8 million increase, partially offset by higher operating costs of $6.6 million. On a combined basis, NGL transportation volumes on these pipelines increased 33 MBPD primarily due to increased production from natural gas processing plants located in the Permian Basin and Rocky Mountains.

Table of Contents

Gross operating margin from our equity investments in the Texas Express Gathering System and the Texas Express Pipeline increased a combined $18.3 million year-to-year primarily due to contractual increases in committed shipper volumes. Gross operating margin from our Dixie Pipeline and related terminals increased a $9.9 million year-to-year primarily due to higher transportation volumes, which increased 19 MBPD year-to-year. Gross operating margin from our Tri-States NGL Pipeline increased $8.7 million year-to-year primarily due to a 10 MBPD (net to our interest) increase in transportation volumes.

Gross operating margin from our South Texas NGL Pipeline System decreased a net $25.6 million year-to-year primarily due to lower average transportation fees, which accounted for a $13.7 million decrease, lower transportation volumes, which accounted for a $7.0 million of the decrease, and higher maintenance costs, which accounted for an additional $4.1 million decrease. Transportation volumes for the South Texas NGL Pipeline System decreased 21 MBPD year-to-year.

NGL fractionation

Comparison of 2018 with 2017. Gross operating margin from NGL fractionation for 2018 increased $16.2 million when compared to 2017. Gross operating margin from our Hobbs NGL fractionator increased $10.2 million year-to-year primarily due to higher product blending revenues, which accounted for a $3.2 million increase, and lower maintenance and other operating costs, which accounted for an additional $4.5 million increase. NGL fractionation volumes increased 4 MBPD year-to-year.

Gross operating margin from our Mont Belvieu NGL fractionation complex increased $7.5 million year-to-year primarily due to higher fractionation volumes of 97 MBPD (net to our interest) resulting from the start-up of our ninth NGL fractionator in May 2018. The new fractionator, which is located in Chambers County, Texas, has a capacity of 90 MBPD, which increased total NGL fractionation capacity at our Mont Belvieu complex to 760 MBPD.

Comparison of 2017 with 2016. Gross operating margin from NGL fractionation for 2017 increased a net $7.5 million when compared to 2016. Gross operating margin from our Mont Belvieu NGL fractionation complex increased a net $4.1 million primarily due to higher average fractionation fees and blending revenues, which accounted for a $50.8 million increase, partially offset by higher storage, maintenance and power expenses of $47.3 million. NGL fractionation volumes increased 9 MBPD year-to-year, net to our interest.

Crude Oil Pipelines & Services

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

	For the Year Ended December 31,		
	2018	2017	2016
Segment gross operating margin:			
Midland-to-ECHO 1 Pipeline System and related business activities, excluding associated non-cash mark-to-market results	$349.3	$45.8	
Mark-to-market loss attributable to the Midland-to-ECHO 1 Pipeline System	(44.6)	(20.5)	
Total Midland-to-ECHO 1 Pipeline System and related business activities	304.7	25.3	
Other crude oil pipelines, terminals and related marketing results	1,206.6	961.9	$854.6
Total	$1,511.3	$987.2	$854.6
Selected volumetric data:			
Crude oil pipeline transportation volumes (MBPD)	2,000	1,820	1,388

Crude oil marine terminal volumes (MBPD)	684	531	495

Midland-to-ECHO 1 Pipeline System and related business activities

Gross operating margin from our Midland-to-ECHO 1 Pipeline System and related business activities was a combined $304.7 million for 2018 compared to a combined $25.3 million in 2017. Transportation volumes for the Midland-to-ECHO 1 Pipeline System, which entered limited service in November 2017 and full service in April 2018, averaged 437 MBPD and 333 MBPD during 2018 and 2017, respectively (net to our interest).

Gross operating margin for this business for 2018 reflects a non-cash mark-to-market loss of $44.6 million associated with the hedging of crude oil market price differentials (basis spreads) between the Midland and Houston area markets.

83

Table of Contents

These hedges, which were primarily entered into during 2017, serve to lock in a positive margin on our anticipated purchases of crude oil at Midland and subsequent anticipated sales to customers in the Houston area for periods extending predominantly into 2019 and minimally through 2020. At December 31, 2018, these hedges represented a weighted average of approximately 22% of the pipeline's expected uncommitted capacity through 2020 at an average positive margin of $2.76 per barrel. The mark-to-market loss reflects a widening of the basis spread between the Midland and Houston markets to an average of $8.48 per barrel through 2020 relative to our average hedged amount of $2.76 per barrel across these same periods (as of December 31, 2018).

Basis swaps, in all but very limited circumstances, do not qualify for cash flow hedge accounting despite being highly effective at hedging the price risk inherent in the underlying physical transactions. The volume hedged through 2020 varies from quarter-to-quarter and year-to-year; however, the hedge levels generally correspond to pipeline capacity currently expected to be available to us during the first three years of the pipeline's operations as customer commitment volumes ramp up to peak levels.

If the basis spreads underlying these hedges widen from the levels at December 31, 2018, we would be exposed to additional temporary non-cash mark-to-market losses. Conversely, if basis spreads narrow in the future reverting back towards or below the average $2.76 per barrel spread we have locked in at December 31, 2018, then we would recognize temporary non-cash mark-to-market gains in future periods. When the forecasted physical receipts and deliveries of crude oil ultimately occur in the future, we will realize a physical gross margin at then prevailing commodity price spreads; however the realized settlement of the associated financial hedges would convert that physical margin to the average $2.76 per barrel spread of the financial hedges. At that time, the unrealized mark-to-market loss recognized for 2018 and in future periods until the physical deliveries occur will be reversed, thus eliminating their impact to cumulative earnings recognized over the entire life-to-date period of the hedge.

The basis spread between the Midland and Houston markets continues to fluctuate. We also have uncommitted capacity on the pipeline that could provide us with potential upside to widening or downside to narrowing market spreads. For information regarding our crude oil marketing hedging portfolio, see Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

Gross operating margin for 2018 was also reduced by $33.9 million in connection with the allocation of pipeline earnings to Western upon closing of their acquisition of a noncontrolling 20% equity interest in the pipeline on June 1, 2018.

Other crude oil pipelines, terminals and related marketing results

Comparison of 2018 with 2017. Gross operating margin from our other crude oil pipelines, terminals and related marketing activities for 2018 increased a net $244.7 million when compared to 2017. Gross operating margin from our South Texas Crude Oil Pipeline System increased a net $71.1 million year-to-year primarily due to higher firm capacity reservation fees, which accounted for $43.3 million of the increase, and higher deficiency fee revenues associated with producer volume commitments, which accounted for a $22.9 million increase. The increase in firm capacity reservation fees is attributable to use of the Rancho II pipeline by the Midland-to-ECHO 1 Pipeline System. Crude oil transportation volumes for the South Texas Crude Oil Pipeline System decreased 5 MBPD year-to-year.

Gross operating margin from crude oil export activities at EHT increased $49.6 million year-to-year primarily due to higher net loading volumes, which increased 152 MBPD year-to-year. Gross operating margin from our Midland and ECHO terminals increased a combined $24.5 million year-to-year primarily due to higher throughput volumes attributable to movements on the Midland-to-ECHO 1 Pipeline System.

Gross operating margin from our West Texas System and equity investment in the Eagle Ford Crude Oil Pipeline System increased a combined $44.2 million year-to-year primarily due to higher transportation volumes, which increased 85 MBPD (net to our interest).

Table of Contents

Gross operating margin from our EFS Midstream System increased $23.5 million year-to-year primarily due to higher deficiency fee revenues. Condensate and natural gas transportation volumes for this system decreased 2 MBPD and 39 MMcf/d, respectively, year-to-year. Although gross operating margin for this system decreased $15.9 million year-to-year attributable to lower throughput volumes, the decrease was more than offset by a $34.3 million year-to-year increase in deficiency fee revenues associated with producer volume commitments. These volume commitments begin to expire in mid-2022. Based on our forecast of drilling activity in the region served by the EFS Midstream System, we expect that production volumes will increase in the coming years, thus offsetting the decline in contractual producer volume commitments.

Gross operating margin from our equity investment in the Seaway Pipeline decreased $16.9 million year-to-year primarily due to lower average transportation fees attributable to an increase in walk-up shipper volumes, which are charged a lower tariff. Transportation volumes for Seaway decreased 9 MBPD year-to-year (net to our interest).

Gross operating margin from our related crude oil marketing activities increased a net $55.9 million year-to-year primarily due to higher average sales margins, which accounted for a $69.2 million increase, partially offset by lower non-cash mark-to-market results, which accounted for a $15.2 million decrease. Non-cash mark-to-market earnings for this business was a gain of $0.5 million for 2018 versus a gain of $15.7 million for 2017. Average sales margins increased in 2018 primarily due to higher market price differentials for crude oil between the Permian Basin region, Cushing hub and Gulf Coast markets. As crude oil production in the Permian Basin region increased in 2018, pipeline infrastructure constraints led to pricing dislocations in the supply basins (lower crude oil prices in West Texas) compared to the prices paid by end users and exporters along the Gulf Coast. As midstream infrastructure constraints are alleviated in the coming years, we expect that these market price differentials will normalize.

Comparison of 2017 with 2016. Gross operating margin from our other crude oil pipelines, terminals and related marketing activities for 2017 increased a net $107.3 million when compared to 2016. Gross operating margin from our West Texas System and equity investment in the Eagle Ford Crude Oil Pipeline System increased a combined $54.7 million year-to-year primarily due to an 89 MBPD increase in crude oil transportation volumes (net to our interest).

Gross operating margin from our EFS Midstream System increased $31.7 million year-to-year primarily due to increased deficiency fee revenues. Condensate transportation volumes for this system decreased 18 MBPD year-to-year and associated natural gas volumes decreased 101 MMcf/d year-to-year. Gross operating margin for the system decreased $59.7 million year-to-year primarily due to the lower throughput volumes; however, this decrease was more than offset by a $98.1 million year-to-year increase in deficiency fee revenues associated with producer volume commitments.

Gross operating margin from our South Texas Crude Oil Pipeline System increased $25.0 million primarily due to higher firm capacity reservation fees, which accounted for a $17.1 million increase and was attributable to use of the Rancho II pipeline by the Midland-to-ECHO 1 Pipeline System. Crude oil transportation volumes for the South Texas Crude Oil Pipeline System decreased 9 MBPD year-to-year.

Gross operating margin from our related crude oil marketing activities decreased a net $5.3 million year-to-year primarily due to lower average sales margins, which accounted for a $39.0 million decrease, lower sales volumes, which accounted for a $38.2 million decrease, partially offset by a $56.1 million benefit related to non-cash mark-to-market results, lower pipeline-related costs, which accounted for a $7.8 million increase, and higher earnings from trucking activities, which accounted for an additional $7.5 million increase. Non-cash mark-to-market earnings for this business was a gain of $15.7 million for 2017 versus a loss of $40.4 million for 2016.

Table of Contents

Natural Gas Pipelines & Services

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

	For the Year Ended December 31,		
	2018	2017	2016
Segment gross operating margin	$891.2	$714.5	$734.9
Selected volumetric data:			
Natural gas pipeline transportation volumes (BBtus/d)	13,727	12,305	11,874

Comparison of 2018 with 2017. Gross operating margin from our Natural Gas Pipelines & Services segment for 2018 increased a net $176.7 million when compared to 2017. Gross operating margin from our Texas Intrastate System increased $75.6 million year-to-year primarily due to higher average firm capacity reservation fees, which accounted for a $62.6 million increase, and higher average transportation fees, which accounted for an additional $19.3 million increase, partially offset by higher maintenance and other operating costs, which accounted for a $14.8 million decrease. Due to market price differentials for natural gas between the Permian Basin region and Gulf Coast markets, shippers were willing to pay higher prices for firm capacity and spot transportation arrangements in 2018. Natural gas transportation volumes on our Texas Intrastate System increased 119 BBtus/d year-to-year.

Gross operating margin from our natural gas marketing activities increased $41.1 million year-to-year primarily due to higher average sales margins, which accounted for a $23.5 million increase, and higher non-cash mark-to-market earnings, which accounted for an additional $13.2 million increase. Average sales margins increased in 2018 primarily due to higher market price differentials for natural gas between the Permian Basin region and Gulf Coast markets. As crude oil and associated natural gas production in the Permian Basin region increased in 2018, pipeline infrastructure constraints led to pricing dislocations in the supply basins (lower natural gas prices in West Texas) compared to the prices paid by end users and exporters along the Gulf Coast. As midstream infrastructure constraints are alleviated in the coming years, we expect that these market price differentials will normalize.

Gross operating margin from our Haynesville Gathering System increased a net $26.2 million year-to-year primarily due to higher gathering volumes, which accounted for a $16.8 million increase, higher treating and other fee revenues, which accounted for an additional $14.1 million increase, partially offset by higher maintenance and other operating costs, which accounted for a $4.7 million decrease. Natural gas gathering volumes on the Haynesville Gathering System increased 318 BBtus/d due to prolific production from the Haynesville Shale region. Gross operating margin from our Acadian Gas System decreased a net $11.7 million year-to-year primarily due to a $17.4 million benefit recorded in the second quarter of 2017 for proceeds we received in a legal settlement for lost revenues and damages associated with the Bayou Corne sinkhole incident caused by third parties in 2012, partially offset by higher average firm capacity reservation fees on the Haynesville Extension pipeline, which accounted for an $11.0 million increase. Transportation volumes for the Acadian Gas System increased 420 BBtus/d year-to-year, with the Haynesville Extension pipeline accounting for 379 BBtus/d of the increase.

Gross operating margin from our Permian Basin Gathering System increased $21.3 million year-to-year primarily due to a 287 BBtus/d increase in natural gas gathering volumes, which accounted for a $28.5 million increase, partially offset by higher costs at our Waha facility during the fourth quarter of 2018, which accounted for a $6.1 million decrease. Natural gas production in the Permian Basin region continues to rise as a result of the significant increases in crude oil production across West Texas and southeastern New Mexico.

Gross operating margin from our BTA Gathering System, which we acquired in April 2017, increased $14.4 million year-to-year primarily due to higher gathering volumes of 91 BBtus/d.

Comparison of 2017 with 2016. Gross operating margin from our Natural Gas Pipelines & Services segment for 2017 decreased a net $20.4 million when compared to 2016.

Table of Contents

Gross operating margin from our Texas Intrastate System decreased $51.4 million year-to-year primarily due to lower firm capacity reservation fees, which accounted for a $30.1 million decrease, lower natural gas transportation volumes, which accounted for an $8.5 million decrease, lower average transportation fees, which accounted for a $7.1 million decrease, and increased operating costs, which accounted for an additional $3.4 million decrease. The $30.1 million decrease in firm capacity reservation fees in 2017 is primarily due to the settlement of a customer contract in the fourth quarter of 2016. Natural gas transportation volumes for the Texas Intrastate System decreased 324 BBtus/d year-to-year primarily due to reduced producer activity in the Eagle Ford and Barnett Shale areas in 2017.

Gross operating margin from our Jonah Gathering System decreased $12.3 million year-to-year primarily due to lower average gathering fees, which accounted for a $6.5 million decrease, a 32 BBtus/d decline in natural gas gathering volumes, which accounted for a $3.4 million decrease, and higher operating costs, which accounted for an additional $3.2 million decrease.

Gross operating margin from our Permian Basin Gathering System increased $10.5 million year-to-year primarily due to a 60 BBtus/d increase in natural gas gathering volumes on the Carlsbad Pipeline, which accounted for a $7.0 million increase, and higher condensate sales revenues, which accounted for an additional $2.4 million increase.

Gross operating margin from our BTA Gathering System, which we acquired in April 2017, was $9.0 million on gathering volumes of 220 BBtus/d. Gross operating margin from our Acadian Gas System increased a net $7.1 million year-to-year primarily due to the $17.4 million benefit related to the Bayou Corne incident described previously, partially offset by lower firm capacity reservation revenues on the Haynesville Extension pipeline, which accounted for a $6.4 million year-to-year decrease, and lower average gathering fees, which accounted for an additional $1.8 million decrease. Transportation volumes for the Acadian Gas System increased 343 BBtus/d year-to-year, with the Haynesville Extension pipeline accounting for 308 BBtus/d of the increase. Gross operating margin from our Haynesville Gathering System increased a net $8.4 million year-to-year primarily due to higher gathering volumes, which accounted for an $11.7 million increase, partially offset by the effects of lower average gathering fees, which accounted for a $2.8 million decrease. Natural gas gathering volumes for the Haynesville Gathering System increased 213 BBtus/d.

Gross operating margin from our natural gas marketing activities increased a net $8.8 million year-to-year primarily due to an increase in average sales margins, which accounted for a $7.9 million increase, and higher sales volumes, which accounted for an additional $4.8 million increase, partially offset by lower non-cash mark-to-market earnings, which accounted for a $3.9 million decrease.

Petrochemical & Refined Products Services

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

	For the Year Ended December 31,		
	2018	2017	2016
Segment gross operating margin:			
Propylene production and related activities	$462.6	$222.4	$212.1
Butane isomerization and related operations	93.4	72.3	52.0
Octane enhancement and related plant operations	154.1	122.6	42.2
Refined products pipelines and related activities	320.3	280.1	305.6
Marine transportation	27.4	17.2	38.7
Total	$1,057.8	$714.6	$650.6

Selected volumetric data:			
Propylene production volumes (MBPD)	98	80	73
Butane isomerization volumes (MBPD)	107	107	108
Standalone DIB processing volumes (MBPD)	89	82	89
Octane additive and related plant production volumes (MBPD)	28	26	22
Pipeline transportation volumes, primarily refined products & petrochemicals (MBPD)	821	792	837
Refined products and petrochemical marine terminal volumes (MBPD)	353	406	389

Table of Contents

Propylene production and related activities

Comparison of 2018 with 2017. Gross operating margin from propylene production and related marketing activities for 2018 increased $240.2 million when compared to 2017. Our PDH facility, which completed its commissioning (or start up) phase and began full commercial operations in April 2018, contributed $104.4 million of gross operating margin in 2018. Plant production volumes for the PDH facility, including by-products, averaged 20 MBPD during 2018. Gross operating margin from our Mont Belvieu propylene splitters increased $91.2 million year-to-year primarily due to higher average propylene sales margins, which accounted for a $108.8 million increase, and higher average propylene fractionation fees, which accounted for an additional $14.6 million increase, partially offset by lower propylene sales volumes, which accounted for a $34.6 million decrease, and higher major maintenance costs, which accounted for an additional $7.5 million decrease. Lastly, gross operating margin from our propylene pipelines increased a net $16.5 million year-to-year primarily due to expansion projects in south Louisiana being placed into service during the fourth quarter of 2017. Transportation volumes for our propylene pipelines increased an aggregate 20 MBPD year-to-year.

Comparison of 2017 with 2016. Gross operating margin from propylene production and related marketing activities for 2017 increased a net $10.3 million when compared to 2016. Gross operating margin from our Mont Belvieu propylene splitters increased a net $33.0 million year-to-year primarily due to higher average propylene sales margins and volumes, which accounted for $24.4 million and $19.1 million, respectively, of increases, along with higher average propylene fractionation fees, which accounted for an additional $13.8 million increase, partially offset by higher storage, major maintenance and other operating costs, which accounted for a combined $23.9 million decrease. The increase in gross operating margin from our Mont Belvieu propylene splitters was partially offset by higher commissioning costs of the PDH facility in 2017, which increased $13.3 million year-to-year.

Butane isomerization and related DIB operations

Comparison of 2018 with 2017. Gross operating margin from butane isomerization and related DIB operations for 2018 increased $21.1 million when compared to 2017 primarily due to higher by-product sales volumes, which accounted for a $14.5 million increase, and higher average isomerization fees, which accounted for an additional $5.0 million increase.

Comparison of 2017 with 2016. Gross operating margin from butane isomerization and related DIB operations for 2017 increased $20.3 million when compared to 2016 primarily due to lower major maintenance and other operating costs, which accounted for a $15.5 million decrease, and higher by-product revenues. By-product sales revenues increased a net $7.2 million year-to-year primarily due to higher average sales prices, which accounted for a $21.7 million increase, partially offset by lower sales volumes, which accounted for a $14.5 million decrease.

Octane enhancement and related operations

Comparison of 2018 with 2017. Gross operating margin for 2018 from our octane enhancement facility and high purity isobutylene plant (“HPIB”) increased a combined $31.5 million when compared to 2017. Gross operating margin from our octane enhancement facility increased $32.3 million year-to-year primarily due to higher sales volumes and average sales margins, which accounted for increases of $20.0 million and $15.4 million, respectively.

Comparison of 2017 with 2016. Gross operating margin from our octane enhancement facility and HPIB plant for 2017 increased $80.4 million when compared to 2016. Gross operating margin from our octane enhancement facility increased $80.7 million year-to-year primarily due to lower major maintenance costs, which accounted for a $42.6 million increase, and higher sales volumes, which accounted for an additional $30.5 million increase. Historically, our octane enhancement plant experienced downtime annually for major maintenance activities. During 2016, we completed significant modifications to our octane enhancement plant to alleviate the need for such yearly outages. We now expect downtime for major maintenance activities at our octane enhancement plant once every three years.

88

Table of Contents

Refined products pipelines and related activities
Comparison of 2018 with 2017. Gross operating margin from refined products pipelines and related marketing activities for 2018 increased a net $40.2 million when compared to 2017. Gross operating margin from our TE Products Pipeline increased $34.8 million year-to-year primarily due to higher average transportation and other fees, which accounted for a combined $19.6 million increase, and higher transportation volumes, which accounted for an additional $18.2 million increase. Transportation volumes on the TE Products Pipeline increased a net 6 MBPD year-to-year primarily due to higher NGL transportation volumes of 14 MBPD, partially offset by lower petrochemical transportation volumes of 8 MBPD.

Gross operating margin from our refined products marketing activities increased $14.3 million primarily due to higher average refined products sales margins.

Gross operating margin from our Houston Ship Channel refined products marine terminal decreased $6.9 million year-to-year primarily due to lower storage revenues.

Comparison of 2017 with 2016. Gross operating margin from refined products pipelines and related marketing activities for 2017 decreased a net $25.5 million when compared to 2016. Gross operating margin from refined products marketing decreased a net $18.3 million year-to-year primarily due to lower average refined products sales margins, which accounted for a $30.0 million decrease, partially offset by a $12.0 million year-to-year increase in non-cash mark-to-market income. Gross operating margin from our Beaumont and Houston Ship Channel refined products marine terminals decreased a combined $14.2 million year-to-year primarily due to higher operating costs.

Gross operating margin from our TE Products Pipeline increased a net $7.3 million year-to-year primarily due to higher average transportation fees, which accounted for a $10.8 million increase, partially offset by lower transportation volumes, which accounted for a $5.8 million decrease. Transportation volumes for the TE Products Pipeline decreased 24 MBPD primarily due to lower movements of refined products and petrochemicals during 2017.

Marine transportation
Comparison of 2018 with 2017. Gross operating margin from marine transportation for 2018 increased $10.2 million when compared to 2017 primarily due to higher marine vessel utilization rates year-to-year.

Comparison of 2017 with 2016. Gross operating margin from marine transportation for 2017 decreased $21.5 million when compared to 2016 primarily due to lower average fees.

Liquidity and Capital Resources

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. At December 31, 2018, we had $6.34 billion of consolidated liquidity, which was comprised of $6.0 billion of available borrowing capacity under EPO's revolving credit facilities and $344.8 million of unrestricted cash on hand.

We have a universal shelf registration statement (the "2016 Shelf") on file with the SEC which allows Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. EPO issued $5.7 billion aggregate principal amount of senior notes and junior subordinated notes using the 2016 Shelf during the year ended December 31, 2018. The 2016 Shelf will expire in May 2019, and we expect to file a replacement universal shelf registration statement at or before such time. We may issue additional equity and debt securities in the future to assist us in meeting our funding and liquidity requirements, including those related to capital investments.

Table of Contents

Consolidated Debt

The following table presents scheduled maturities of our consolidated debt obligations outstanding at December 31, 2018 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	2019	2020	2021	2022	2023	Thereafter
Senior Notes	$23,750.0	$1,500.0	$1,500.0	$1,325.0	$1,400.0	$1,250.0	$16,775.0
Junior Subordinated Notes	2,670.6	--	--	--	--	--	2,670.6
Total	$26,420.6	$1,500.0	$1,500.0	$1,325.0	$1,400.0	$1,250.0	$19,445.6

For additional information regarding our debt agreements, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Issuance of $3.0 Billion of Senior Notes in October 2018

In October 2018, EPO issued $3.0 billion aggregate principal amount of senior notes comprised of (i) $750 million principal amount of senior notes due February 2022 (“Senior Notes VV”), (ii) $1.0 billion principal amount of senior notes due October 2028 (“Senior Notes WW”) and (iii) $1.25 billion principal amount of senior notes due February 2049 (“Senior Notes XX”). Net proceeds from this offering were used by EPO for the temporary repayment of amounts outstanding under its commercial paper program and general company purposes, including for growth capital expenditures.

Senior Notes VV were issued at 99.985% of their principal amount and have a fixed-rate interest rate of 3.50% per year. Senior Notes WW were issued at 99.764% of their principal amount and have a fixed-rate interest rate of 4.15% per year. Senior Notes XX were issued at 99.390% of their principal amount and have a fixed-rate interest rate of 4.80% per year. Enterprise Products Partners L.P. has guaranteed the senior notes through an unconditional guarantee on an unsecured and unsubordinated basis.

Issuance of $2.0 Billion of Senior Notes and $700 Million of Junior Subordinated Notes in February 2018

In February 2018, EPO issued $2.7 billion aggregate principal amount of notes comprised of (i) $750 million principal amount of senior notes due February 2021 (“Senior Notes TT”), (ii) $1.25 billion principal amount of senior notes due February 2048 (“Senior Notes UU”) and (iii) $700 million principal amount of junior subordinated notes due February 2078 (“Junior Subordinated Notes F”). Net proceeds from these offerings were used by EPO for the temporary repayment of amounts outstanding under its commercial paper program, general company purposes, and the redemption of all $682.7 million outstanding aggregate principal amount of its Junior Subordinated Notes B.

Senior Notes TT were issued at 99.946% of their principal amount and have a fixed-rate interest rate of 2.80% per year. Senior Notes UU were issued at 99.865% of their principal amount and have a fixed-rate interest rate of 4.25% per year. Enterprise Products Partners L.P. has guaranteed the senior notes through an unconditional guarantee on an unsecured and unsubordinated basis.

The Junior Subordinated Notes F are redeemable at EPO’s option, in whole or in part, on one or more occasions, on or after February 15, 2028 at 100% of their principal amount, plus any accrued and unpaid interest thereon, and bear interest at a fixed rate of 5.375% per year through February 14, 2028. Beginning February 15, 2028, the Junior Subordinated Notes F will bear interest at a floating rate based on a three-month LIBOR plus 2.57%, reset quarterly. Enterprise Products Partners L.P. has guaranteed the Junior Subordinated Notes F through an unconditional guarantee on an unsecured and subordinated basis.

Redemption of Junior Subordinated Notes

In March 2018, EPO redeemed all of the $682.7 million outstanding aggregate principal amount of its Junior Subordinated Notes B at a price equal to 100% of the principal amount of the notes being redeemed, plus all accrued and unpaid interest thereon to, but not including, the redemption date. This redemption was funded by EPO's issuance of senior notes and junior subordinated notes in February 2018.

Table of Contents

In August 2018, EPO redeemed all of the $521.1 million outstanding aggregate principal amount of its Junior Subordinated Notes A at a price equal to 100% of the principal amount of the notes being redeemed, plus all accrued and unpaid interest thereon to, but not including, the redemption date. This redemption was funded by the issuance of short-term notes under EPO's commercial paper program.

364-Day Revolving Credit Agreement

In September 2018, EPO entered into a 364-Day Revolving Credit Agreement that replaced its prior 364-day credit facility. The new 364-Day Revolving Credit Agreement matures in September 2019. There are currently no principal amounts outstanding under this revolving credit agreement.

Under the terms of the new 364-Day Revolving Credit Agreement, EPO may borrow up to $2.0 billion (which may be increased by up to $200 million to $2.2 billion at EPO's election, provided certain conditions are met) at a variable interest rate for a term of up to 364 days, subject to the terms and conditions set forth therein. To the extent that principal amounts are outstanding at the maturity date, EPO may elect to have the entire principal balance then outstanding continued as a non-revolving term loan for a period of one additional year, payable in September 2020. Borrowings under this revolving credit agreement may be used for working capital, capital expenditures, acquisitions and general company purposes.

The new 364-Day Revolving Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of any amounts borrowed under this credit agreement. The credit agreement also restricts EPO's ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

EPO's obligations under the new 364-Day Revolving Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P.

Increase in Amount Authorized under Commercial Paper Program

In June 2018, EPO increased the aggregate principal amount of short-term notes that it could issue (and have outstanding at any time) under its commercial paper program from $2.5 billion to $3.0 billion. The commercial paper program enables us to access typically lower short-term interest rates, which allows us to manage working capital and our overall cost of capital. As a back-stop to the commercial paper program, we intend to maintain a minimum available borrowing capacity under EPO's Multi-Year Revolving Credit Facility equal to the outstanding aggregate principal amount of EPO's commercial paper notes. All commercial paper notes issued under the program are senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P. At December 31, 2018, we had no commercial paper notes outstanding.

Credit Ratings

At March 1, 2019, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's, Baa1 from Moody's and BBB+ from Fitch Ratings. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's, P-2 from Moody's and F-2 from Fitch Ratings.

EPO's credit ratings reflect only the view of a rating agency and should not be interpreted as a recommendation to buy, sell or hold any of our securities. A credit rating can be revised upward or downward or withdrawn at any time by a rating agency, if it determines that circumstances warrant such a change. A credit rating from one rating agency should be evaluated independently of credit ratings from other rating agencies.

Common Unit Buyback Program

In December 1998, we announced a common unit buyback program whereby we, together with certain affiliates, could repurchase up to 4,000,000 of our common units on the open market. We purchased the remaining authorized amount of 1,236,800 common units in late December 2018 for $30.8 million at an average price of $24.92 per unit.

Table of Contents

In January 2019, we announced that the Board of Enterprise GP had approved a $2.0 billion multi-year common unit buyback program, which provides the partnership with an additional method to return capital to investors. See "Significant Recent Developments" within this Part II, Item 7 for additional information.

Issuance of Common Units

The following table summarizes the issuance of common units in connection with our at-the-market ("ATM") program, distribution reinvestment plan ("DRIP") and employee unit purchase plan ("EUPP") for the years indicated (dollars in millions, number of units issued as shown):

	Number of Common Units Issued	Net Cash Proceeds Received
Year Ended December 31, 2016:		
Common units issued in connection with ATM program	87,867,037	$2,156.1
Common units issued in connection with DRIP and EUPP	16,316,534	386.7
Total	104,183,571	$2,542.8
Year Ended December 31, 2017:		
Common units issued in connection with ATM program	21,807,726	$597.0
Common units issued in connection with DRIP and EUPP	19,046,019	476.4
Total	40,853,745	$1,073.4
Year Ended December 31, 2018:		
Common units issued in connection with DRIP and EUPP (1)	19,861,951	$538.4

(1) The net cash proceeds we received from the issuance of common units during 2018 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and for general company purposes.

ATM Program

We have a registration statement on file with the SEC covering the issuance of up to $2.54 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings in connection with our ATM program. Pursuant to this program, we may sell common units from time-to-time under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement. After taking into account the aggregate sales price of common units sold under the ATM program through December 31, 2018, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $2.54 billion. We did not issue any common units under the ATM program during the year ended December 31, 2018.

DRIP and EUPP

We have a registration statement on file with the SEC in connection with our DRIP. The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of our common units they own by reinvesting the quarterly cash distributions they receive from us into the purchase of additional common units at a discount ranging from 0% to 5%. Beginning with the distribution declared with respect to the fourth quarter of 2017 and paid in February 2018, the discount was reduced from 5% to 2.5%. Likewise, beginning with the distribution declared with respect to the fourth quarter of 2018 and paid in February 2019, the discount was reduced from 2.5% to 0%. We have the sole discretion to determine whether common units purchased under the DRIP will come from our authorized but unissued common units or from common units purchased on the open market by the DRIP administrator.

We issued 19,316,781 new common units, which generated net cash proceeds of $523.3 million, under the DRIP in 2018. After taking into account the number of common units issued under the DRIP through December 31, 2018, we have the capacity to deliver an additional 61,400,359 common units under this plan.

92

Table of Contents

In addition to the DRIP, we have registration statements on file with the SEC in connection with our EUPP. We issued 545,170 new common units, which generated net cash proceeds of $15.1 million, under the EUPP in 2018. After taking into account the number of common units issued under the EUPP through December 31, 2018, we have the capacity to deliver an additional 5,215,641 common units under this plan.

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

Cash Flow Statement Highlights

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

	For the Year Ended December 31,		
	2018	2017	2016
Net cash flows provided by operating activities	$6,126.3	$4,666.3	$4,066.8
Cash used in investing activities	4,281.6	3,286.1	4,005.8
Cash provided by (used in) financing activities	(1,504.9)	(1,727.5)	321.7

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. Changes in energy commodity prices may impact the demand for natural gas, NGLs, crude oil, petrochemical and refined products, which could impact sales of our products and the demand for our midstream services. Changes in demand for our products and services may be caused by other factors, including 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 customers do not fulfill their obligations to us in connection with our marketing activities and long-term take-or-pay agreements. 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. 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. We have a concentration of trade receivable balances due from independent and major integrated oil and gas companies and other pipelines and wholesalers. These concentrations may affect our overall credit risk in that these energy industry customers may be similarly affected by changes in economic, regulatory or other factors. For a more complete discussion of these and other risk factors pertinent to our business, see Part I, Item 1A of this annual report.

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

Operating activities

Comparison of 2018 with 2017. Net cash flows provided by operating activities in 2018 increased $1.46 billion when compared to 2017. The increase in cash provided by operating activities was primarily due to:

§ a $1.43 billion increase in cash resulting from higher partnership earnings in 2018 compared to 2017 (after adjusting our $1.38 billion year-to-year increase in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows); and

§ a $45.7 million year-to-year increase in cash distributions received on earnings from unconsolidated affiliates primarily due to our investments in NGL pipeline businesses.

For information regarding significant year-to-year changes in our consolidated net income and underlying segment results, see “Results of Operations” within this Part II, Item 7.
93

Table of Contents

Comparison of 2017 with 2016. Net cash flows provided by operating activities in 2017 increased $599.5 million when compared to 2016. The increase in cash provided by operating activities was primarily due to:

§ a $333.2 million increase in cash resulting from higher partnership earnings in 2017 compared to 2016 (after adjusting our $302.6 million year-to-year increase in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows);

§ a $213.1 million year-to-year increase in cash primarily due to the timing of cash receipts and payments related to operations; and

§ a $53.2 million year-to-year increase in cash distributions received on earnings from unconsolidated affiliates primarily due to our investments in crude oil pipeline businesses.

Investing activities

Comparison of 2018 with 2017. Cash used for investing activities in 2018 increased $995.5 million when compared to 2017 primarily due to:

§ a $1.12 billion year-to-year increase in expenditures for consolidated property, plant and equipment (see "Capital Investments" within this Part II, Item 7 for additional information); and

§ a $63.1 million year-to-year increase in investments in unconsolidated affiliates primarily related to NGL and crude oil pipeline projects; partially offset by

§ a $121.1 million year-to-year increase in proceeds from assets sales primarily due to the sale of our former Red River System in October 2018 for $134.9 million; and

§ a $48.1 million year-to-year decrease in net cash used for business combinations. We used $150.6 million in 2018 to acquire the remaining 50% equity interest in Delaware Processing. For 2017, we used $191.4 million to acquire the BTA Gathering System and related assets.

Comparison of 2017 with 2016. Cash used for investing activities in 2017 decreased $719.7 million when compared to 2016 primarily due to:

§ an $801.3 million year-to-year decrease in cash used for business combinations, net of cash received. In 2017, net cash used for business combinations was $198.7 million, which was primarily attributable to our acquisition of the BTA Gathering System and related assets. In 2016, we paid the second and final installment for the acquisition of the EFS Midstream System; and

§ an $88.3 million year-to-year decrease in investments in unconsolidated affiliates primarily due to the completion of various NGL and crude oil projects; partially offset by

§ a $117.7 million year-to-year increase in expenditures for consolidated property, plant and equipment.

Financing activities

Comparison of 2018 with 2017. Cash used in financing activities for 2018 decreased $222.6 million when compared to 2017 primarily due to:

§ a $775.9 million year-to-year increase in net cash inflows attributable to our consolidated debt obligations. EPO issued $5.7 billion and repaid or redeemed $2.3 billion in principal amount of senior and junior subordinated notes during 2018 compared to the issuance of $1.7 billion in principal amount of junior subordinated notes and the repayment of $800.0 million in principal amount of senior notes during 2017. In addition, net repayments of short term notes under EPO's commercial paper program increased $1.71 billion year-to-year; and

Table of Contents

- § a $237.7 million year-to-year increase in contributions from noncontrolling interests. In June 2018, Western acquired a noncontrolling 20% equity interest in our consolidated subsidiary that owns the Midland-to-ECHO 1 Pipeline System for $189.6 million in cash. In addition, during 2018 we received $41.0 million of contributions for the construction of our jointly-owned ethylene export facility; partially offset by

- § a $535.0 million year-to-year decrease in net cash proceeds from the issuance of common units. We issued an aggregate 19,861,951 common units, which generated $538.4 million of net cash proceeds, in connection with our DRIP and EUPP during 2018. This compares to an aggregate 40,853,745 common units we issued in connection with our ATM, DRIP and EUPP during 2017, which collectively generated $1.07 billion of net cash proceeds;

- § a $157.0 million year-to-year increase in cash distributions paid to limited partners during 2018 when compared to 2017. The increase in cash distributions is due to increases in both the number of distribution-bearing common units outstanding and the quarterly cash distribution rates per unit;

- § a $32.4 million year-to-year increase in cash distributions paid to noncontrolling interests primarily related to the Midland-to-ECHO 1 Pipeline System; and

- § a $30.8 million repurchase of common units under a legacy buyback program in December 2018.

Comparison of 2017 with 2016. Cash used in financing activities for 2017 was $1.73 billion compared to cash provided by financing activities of $321.7 million for 2016. The $2.05 billion year-to-year change in cash flow from financing activities was primarily due to:

- § a $1.47 billion year-to-year decrease in net cash proceeds from the issuance of common units. We issued an aggregate 40,853,745 common units, which generated $1.07 billion of net cash proceeds, in connection with our ATM program, DRIP and EUPP during 2017. This compares to an aggregate 104,183,571 common units we issued in connection with these programs and plans during 2016, which collectively generated $2.54 billion of net cash proceeds;

- § a $285.6 million year-to-year decrease in net cash inflows attributable to our consolidated debt obligations. EPO issued $1.7 billion in principal amount of junior subordinated notes and repaid $800.0 million in principal amount of senior notes during 2017 compared to the issuance of $1.25 billion and repayment of $750.0 million in principal amount of senior notes during 2016. In addition, net repayments under EPO's commercial paper program were $44.2 million during 2017 compared to net issuances of $647.9 million during 2016; and

- § a $269.4 million year-to-year increase in cash distributions paid to limited partners during 2017 when compared to 2016.

Restricted Cash

Restricted cash represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, NGLs, crude oil and refined products. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or margin requirements change. At December 31, 2018 and 2017, our restricted cash amounts were $65.3 million and $65.2 million, respectively.

For information regarding our derivative instruments and hedging activities, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. In addition, see Part II, Item 7A of this annual report.

Table of Contents

Non-GAAP Cash Flow Measures

Distributable Cash Flow
Our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after any cash reserves established by Enterprise GP in its sole discretion. Cash reserves include those for the proper conduct of our business, including those for capital expenditures, debt service, working capital, operating expenses, common unit repurchases, commitments and contingencies and other amounts. The retention of cash by the partnership allows us to reinvest in our growth and reduce our future reliance on the equity and debt capital markets.

In January 2019, the Board declared a cash distribution of $0.4350 per common unit with respect to the fourth quarter of 2018. In addition, our management announced plans to recommend to the Board additional quarterly cash distribution increases of $0.0025 per unit with respect to each of the four quarters of 2019. For additional information regarding our expected distribution growth rate, see "Significant Recent Developments" within this Item 7.

We measure available cash by reference to distributable cash flow ("DCF"), which is a non-GAAP cash flow measure. DCF is an important financial measure for our limited partners since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flows at a level that can sustain our declared quarterly cash distributions. DCF is also a quantitative standard used by the investment community with respect to publicly traded partnerships since the value of a partnership unit is, in part, measured by its yield, which is based on the amount of cash distributions a partnership can pay to a unitholder. Our management compares the DCF we generate to the cash distributions we expect to pay our partners. Using this metric, management computes our distribution coverage ratio. For the year ended December 31, 2018, our distribution coverage ratio was approximately 1.6 times when compared to the sum of our quarterly cash distributions declared with respect to fiscal 2018. Our calculation of DCF may or may not be comparable to similarly titled measures used by other companies.

Based on the level of available cash each quarter, management proposes a quarterly cash distribution rate to the Board of Enterprise GP, which has sole authority in approving such matters. Unlike several other master limited partnerships, our general partner has a non-economic ownership interest in us and is not entitled to receive any cash distributions from us based on incentive distribution rights or other equity interests.

Our use of DCF for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, which is the most comparable GAAP measure. For a discussion of net cash flows provided by operating activities, see "Cash Flows from Operating, Investing and Financing Activities" within this Part II, Item 7.

Table of Contents

The following table summarizes our calculation of DCF for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2018	2017	2016
Net income attributable to limited partners (GAAP) (1)	$4,172.4	$2,799.3	$2,513.1
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP DCF:			
Add non-cash depreciation, amortization and accretion expenses	1,791.6	1,644.0	1,552.0
Add non-cash asset impairment and related charges	50.5	49.8	53.5
Add non-cash expense or subtract benefit attributable to unrealized changes in fair value of derivative instruments	17.8	22.8	45.0
Add non-cash expense attributable to Liquidity Option Agreement	56.1	64.3	24.5
Subtract non-cash gain on step acquisition of unconsolidated affiliate	(39.4)	--	--
Add cash distributions received from unconsolidated affiliates (2)	529.4	483.0	451.5
Subtract equity in income of unconsolidated affiliates	(480.0)	(426.0)	(362.0)
Subtract net gains attributable to asset sales	(28.7)	(10.7)	(2.5)
Add deferred income tax expense	21.4	6.1	6.6
Subtract sustaining capital expenditures (3)	(320.9)	(243.9)	(252.0)
Other miscellaneous adjustments, net	35.9	42.9	20.5
Subtotal DCF, before proceeds from asset sales and monetization of interest rate derivative instruments accounted for as cash flow hedges	$5,806.1	$4,431.6	$4,050.2
Add cash proceeds from asset sales	161.2	40.1	46.5
Add cash proceeds from monetization of interest rate derivative instruments (4)	22.1	30.6	6.1
Distributable cash flow (non-GAAP)	$5,989.4	$4,502.3	$4,102.8
Total cash distributions paid to limited partners with respect to period	$3,777.1	$3,635.2	$3,394.0
Cash distributions per unit declared by Enterprise GP with respect to period (5)	$1.7250	$1.6825	$1.6100
Total distributable cash flow retained by partnership with respect to period (6)	$2,213.3	$867.1	$708.8
Distribution coverage ratio (7)	1.6x	1.2x	1.2x

(1) For a discussion of significant changes in our comparative income statement amounts underlying net income attributable to limited partners, along with the primary drivers of such changes, see “Income Statement Highlights” within this Part II, Item 7.
(2) Reflects both distributions received on earnings from unconsolidated affiliates and those attributable to a return of capital from unconsolidated affiliates.
(3) Sustaining capital expenditures include cash payments and accruals applicable to the period.
(4) For information regarding these gains, see “Interest Rate Hedging Activities” under Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(5) See Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our quarterly cash distributions declared with respect to the years indicated.
(6) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these years was primarily reinvested in growth capital projects. This retainage of cash substantially reduced our reliance on the equity capital markets to fund such expenditures.
(7) Distribution coverage ratio is determined by dividing distributable cash flow by total cash distributions paid to limited partners and in connection with distribution equivalent rights with respect to the period

The following table presents a reconciliation of net cash flows provided by operating activities to DCF for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2018	2017	2016
Net cash flows provided by operating activities (GAAP)	$6,126.3	$4,666.3	$4,066.8
Adjustments to reconcile GAAP net cash flows provided by operating activities to non-GAAP DCF:			
Subtract sustaining capital expenditures	(320.9)	(243.9)	(252.0)
Add cash proceeds from asset sales	161.2	40.1	46.5
Add cash proceeds from monetization of interest rate derivative instruments	22.1	30.6	6.1
Net effect of changes in operating accounts	(16.2)	(32.2)	180.9
Other miscellaneous adjustments, net	16.9	41.4	54.5
Distributable cash flow (non-GAAP)	$5,989.4	$4,502.3	$4,102.8

Table of Contents

Free Cash Flow

Beginning with this annual report, we provide below the non-GAAP financial measure of free cash flow ("FCF"). FCF is a traditional cash flow metric that is widely used by a variety of investors and other participants in the financial community, as opposed to DCF, which is a cash flow measure primarily used by investors and others in evaluating master limited partnerships. In general, FCF is a measure of how much cash flow a business generates during a specified time period after accounting for all capital investments, including expenditures for growth and sustaining capital projects. By comparison, only sustaining capital expenditures are reflected in DCF.

We believe that FCF is important to traditional investors since it reflects the amount of cash available for reducing debt, investing in additional capital projects, paying distributions, common unit repurchases and similar matters. Since business partners fund certain capital projects of our consolidated subsidiaries, our determination of FCF reflects the amount of cash we receive from noncontrolling interests, net of any distributions paid to such interests. Our calculation of FCF may or may not be comparable to similarly titled measures used by other companies.

Our use of FCF for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, which is the most comparable GAAP measure.

The following table summarizes our calculation of FCF for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2018	2017	2016
Net cash flows provided by operating activities (GAAP)	$6,126.3	$4,666.3	$4,066.8
Adjustments to GAAP net cash flows provided by operating activities to derive non-GAAP Free Cash Flow:			
Subtract cash used in investing activities	(4,281.6)	(3,286.1)	(4,005.8)
Add cash contributions from noncontrolling interests	238.1	0.4	20.4
Subtract cash distributions paid to noncontrolling interests	(81.6)	(49.2)	(47.4)
Free cash flow (non-GAAP)	$2,001.2	$1,331.4	$34.0

The elements used in calculating FCF are sourced directly from our statements of consolidated cash flows presented under Part II, Item 8 of this annual report. For a discussion of significant year-to-year changes in our cash flow statement amounts, see "Cash Flows from Operating, Investing and Financing Activities" within this Part II, Item 7.

Capital Investments

An important part of our business strategy involves expansion through growth capital projects, business combinations, asset acquisitions, and investments in joint ventures. We believe that we are well positioned to continue to expand our network of assets through the construction of new facilities and to capitalize on expected increases in natural gas, NGL and crude oil production resulting from development activities in the Permian Basin, Eagle Ford, Haynesville and other domestic shale plays. Although our focus in recent years has been on expansion through growth capital projects, management continues to analyze potential business combinations, asset acquisitions, joint ventures and similar transactions with businesses that operate in complementary markets or geographic regions.

We placed $1.9 billion of major growth capital projects into service during 2018, including our PDH facility, two processing trains at our Orla natural gas processing plant (Orla I and II), and a ninth NGL fractionator located in Chambers County, Texas. We currently have $6.7 billion of growth capital projects scheduled to be completed by the end of 2020 including:

§ the completion of joint venture-owned dock infrastructure in Corpus Christi designed to accommodate crude oil volumes (second quarter of 2019),

§ the Shin Oak NGL pipeline (first quarter of 2019 through fourth quarter of 2019),

§ the third processing train at our Orla natural gas processing facility (second quarter of 2019),

§ expansion of our Front Range and Texas Express NGL pipelines (third quarter of 2019),

Table of Contents

§ our iBDH facility (fourth quarter of 2019),

§ our ethylene export terminal (fourth quarter of 2019 through the fourth quarter of 2020),

§ our Mentone cryogenic natural gas processing plant (first quarter of 2020), and

§ a new NGL fractionation facility in Chambers County, Texas (fourth quarter of 2019 through the first half of 2020).

Based on information currently available, we expect our total capital investments for 2019 to approximate $3.5 billion to $3.9 billion, which reflects growth capital expenditures of $3.1 billion to $3.5 billion and $350 million for sustaining capital expenditures. Our forecast of capital investments for 2019 is based on our announced strategic operating and growth plans (through the filing date of this annual report), which are dependent upon our ability to generate the required funds from either operating cash flows or other means, including borrowings under debt agreements, the issuance of additional equity and debt securities, and potential divestitures. We may revise our forecast of capital investments due to factors beyond our control, such as adverse economic conditions, weather related issues and changes in supplier prices. Furthermore, our forecast of capital investments may change as a result of decisions made by management at a later date, which may include unforeseen acquisition opportunities.

Our success in raising capital, including partnering with other companies to share costs and risks, continues to be a significant factor in determining how much capital we can invest. We believe our access to capital resources is sufficient to meet the demands of our current and future growth needs and, although we expect to make the forecast capital expenditures noted above, we may adjust the timing and amounts of projected expenditures in response to changes in capital market conditions.

The following table summarizes our capital investments for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2018	2017	2016
Capital investments for property, plant and equipment: (1)			
Growth capital projects (2)	$3,902.3	$2,868.8	$2,722.7
Sustaining capital projects (3)	320.9	233.0	261.4
Total	$4,223.2	$3,101.8	$2,984.1
Cash used for business combinations	$150.6	$198.7	$1,000.0
Investments in unconsolidated affiliates	$113.6	$50.5	$138.8

(1) Growth and sustaining capital amounts presented in the table above are presented on a cash basis.
(2) Growth capital projects either (a) result in new sources of cash flow due to enhancements of or additions to existing assets (e.g., additional revenue streams, cost savings resulting from debottlenecking of a facility, etc.) or (b) expand our asset base through construction of new facilities that will generate additional revenue streams and cash flows.
(3) Sustaining capital expenditures are capital expenditures (as defined by GAAP) resulting from improvements to existing assets. Such expenditures serve to maintain existing operations but do not generate additional revenues or result in significant cost savings.

Fluctuations in our expenditures for growth capital projects and investments in unconsolidated affiliates are explained in large part by increases or decreases in spending on major expansion projects. Our most significant growth capital expenditures for the year ended December 31, 2018 involved projects at our Mont Belvieu complex, Houston and Beaumont terminals, as well as projects to support crude oil, natural gas and NGL production from the Permian Basin. Fluctuations in expenditures for sustaining capital projects are explained in large part by the timing and cost of pipeline integrity and similar projects.

Comparison of 2018 with 2017

Investments in growth capital projects supporting Permian Basin production increased $773.0 million year-to-year primarily due to increased expenditures for (i) the Shin Oak NGL Pipeline, which accounted for $839.1 million of the increase, (ii) conversion of a portion of our Seminole NGL Pipeline system to crude oil service (the Midland-to-ECHO 2 Pipeline System), which accounted for an additional $223.4 million increase, partially offset by (iii) a $520.1 million

99

decrease in investment related to our Midland-to-ECHO 1 Pipeline System, which commenced limited service in November 2017 and full service in April 2018.

Investments in growth capital projects to expand and support export activities at EHT increased $161.9 million year-to-year. Additionally, investments in projects that expand our refined products handling capabilities at the Beaumont marine terminal increased $93.9 million year-to-year.

Investments in growth capital projects at our Mont Belvieu complex decreased a net $168.6 million year-to-year, primarily due to decreased expenditures of $529.3 million for our PDH facility and ninth NGL fractionator, which were both placed into commercial service during the second quarter of 2018, partially offset by increased expenditures on our iBDH unit, which accounted for a $224.1 million increase, and our new NGL fractionation facility, which accounted for an additional $123.6 million increase.

Investments in unconsolidated affiliates increased $63.1 million year-to-year primarily due to increased expenditures for certain NGL and crude oil expansion projects.

Net cash used for business combinations decreased $48.1 million year-to-year. We invested $150.6 million in 2018 to acquire the remaining 50% equity interest in Delaware Processing compared to $191.4 million in 2017 to acquire the BTA Gathering System and related assets.

Comparison of 2017 with 2016

Investments in growth capital projects supporting Permian Basin production increased $909.5 million year-to-year primarily due to increased expenditures for the Midland-to-ECHO 1 Pipeline System, which accounted for a $480.2 million increase, construction activities at our Orla natural gas processing plant and related infrastructure, which accounted for an additional $422.1 million increase, partially offset by decreased expenditures on our South Eddy natural gas processing plant and related pipelines, which accounted for a $131.2 million decrease. We completed construction and placed the South Eddy plant into service in May 2016.

Investments in our Morgan's Point Ethane Export Terminal and our LPG export expansion project at EHT decreased a combined $299.3 million. Our Morgan's Point Ethane Export Terminal was placed into service in September 2016.

Investments in growth capital projects at our Mont Belvieu complex decreased $271.9 million year-to-year, primarily due to decreased expenditures at our PDH facility, which accounted for a $443.8 million decrease, partially offset by increased expenditures on our ninth NGL fractionator, which accounted for a $141.9 million increase, and our iBDH unit, which accounted for an additional $93.2 million increase.

Investments in our ECHO and Beaumont Marine West crude oil terminals decreased a combined $103.7 million year-to-year as new storage tanks and related assets were placed into service at these facilities during 2016.

Net cash used for business combinations decreased $801.3 million year-to-year due to the second and final payment of $1.0 billion made in July 2016 for the EFS Midstream System, partially offset by $191.4 million in net cash paid in connection with the acquisition of the BTA Gathering System and related assets in April 2017.

Investments in unconsolidated affiliates decreased $88.3 million year-to-year primarily due to the completion of certain NGL and crude oil expansion projects.

Critical Accounting Policies and Estimates

In our financial reporting processes, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses for each reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect. The following sections discuss the use of estimates within our critical accounting policies:

Table of Contents

Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Depreciation expense incorporates management estimates regarding the useful economic lives and residual values of our assets. At the time we place our assets into service, we believe such assumptions are reasonable; however, circumstances may develop that cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include (i) changes in laws and regulations that limit the estimated economic life of an asset, (ii) changes in technology that render an asset obsolete, (iii) changes in expected residual values or (iv) significant changes in our forecast of the remaining life for the associated resource basins, if applicable.

At December 31, 2018 and 2017, the net carrying value of our property, plant and equipment was $38.74 billion and $35.62 billion, respectively. We recorded $1.44 billion, $1.30 billion and $1.22 billion of depreciation expense for the years ended December 31, 2018, 2017 and 2016, respectively. For additional information regarding our property, plant and equipment, see Note 4 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Measuring Recoverability of Long-Lived Assets and Fair Value of Equity Method Investments

Long-lived assets (including property, plant and equipment and intangible assets with finite useful lives) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable through future cash flows. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil, petrochemicals or refined products.

The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Estimates of undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated residual values. If the carrying value of a long-lived asset is not recoverable, an impairment charge would be recorded for the excess of the asset's carrying value over its estimated fair value, which is derived from an analysis of the asset's estimated future cash flows, the market value of similar assets and replacement cost of the asset less any applicable depreciation or amortization. In addition, fair value estimates also include the usage of probabilities when there is a range of possible outcomes.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible permanent loss in value of the investment (i.e., an "other than a temporary" decline). Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. When evidence of a loss in value has occurred, we compare the estimated fair value of the investment to its carrying value to determine whether an impairment has occurred. We assess the fair value of our equity method investments using commonly accepted techniques, and may use more than one method, including, but not limited to, recent third party sales and discounted estimated cash flow models. Estimates of discounted cash flows are based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful lives of the investment's underlying assets.

A significant change in the assumptions we use to measure recoverability of long-lived assets and the fair value of equity method investments could result in our recording a non-cash impairment charge. Any write-down of the carrying values of such assets would increase operating costs and expenses at that time.

During 2018, 2017 and 2016, we recognized non-cash asset impairment charges related to long-lived assets of $46.8 million, $37.8 million and $45.2 million, respectively, which are a component of costs and expenses. For additional information regarding these impairment charges, see Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report. We did not recognize any impairment charges in connection with our equity-method investments during the three years ended December 31, 2018.

Table of Contents

Valuation and Amortization Methods of Customer Relationships and Contract-Based Intangible Assets

The specific, identifiable intangible assets of an acquired business depend largely upon the nature of its operations and include items such as customer relationships and contracts. The method used to value such assets depends on a number of factors, including the nature of the asset and the economic returns the asset is expected to generate.

Customer relationship intangible assets represent the estimated economic value assigned to commercial relationships acquired in connection with business combinations. In certain instances, the acquisition of these intangible assets provides us with access to customers in a defined resource basin and is analogous to having a franchise in a particular area. Efficient operation of the acquired assets (e.g., a natural gas gathering system) helps to support the commercial relationships with existing producers and provides us with opportunities to establish new ones within our existing asset footprint. The duration of this type of customer relationship is limited by the estimated economic life of the associated resource basin that supports the customer group. When estimating the economic life of a resource basin, we consider a number of factors, including reserve estimates and the economic viability of production and exploration activities.

In other situations, the acquisition of a customer relationship intangible asset provides us with access to customers whose hydrocarbon volumes are not attributable to specific resource basins. As with basin-specific customer relationships, efficient operation of the associated assets (e.g., a marine terminal that handles volumes originating from multiple sources) helps to support the commercial relationships with existing customers and provides us with opportunities to establish new ones. The duration of this type of customer relationship is typically limited to the term of the underlying service contracts, including assumed renewals.

The value we assign to customer relationships is amortized to earnings using methods that closely resemble the pattern in which the estimated economic benefits will be consumed (i.e., the manner in which the intangible asset is expected to contribute directly or indirectly to our cash flows). For example, the amortization period for a basin-specific customer relationship asset is limited by the estimated finite economic life of the associated hydrocarbon resource basin.

Contract-based intangible assets represent specific commercial rights we own arising from discrete contractual agreements, such as the third party customer storage and terminal contracts we acquired in connection with the Oiltanking transaction in October 2014. A contract-based intangible asset with a finite life is amortized over its estimated economic life, which is the period over which the contract is expected to contribute directly or indirectly to our cash flows. Our estimates of the economic life of contract-based intangible assets are based on a number of factors, including (i) the expected useful life of the related tangible assets (e.g., a marine terminal, pipeline or other asset), (ii) any legal or regulatory developments that would impact such contractual rights and (iii) any contractual provisions that enable us to renew or extend such arrangements.

If our assumptions regarding the estimated economic life of an intangible asset were to change, then the amortization period for such asset would be adjusted accordingly. Changes in the estimated useful life of an intangible asset would impact operating costs and expenses prospectively from the date of change. If we determine that an intangible asset's carrying value is not recoverable through its future cash flows, we would be required to reduce the asset's carrying value to its estimated fair value through the recording of a non-cash impairment charge. Any such write-down of the value of an intangible asset would increase operating costs and expenses at that time.

At December 31, 2018 and 2017, the carrying value of our customer relationship and contract-based intangible asset portfolio was $3.61 billion and $3.69 billion, respectively. We recorded $170.3 million, $166.9 million and $171.3 million of amortization expense attributable to intangible assets for the years ended December 31, 2018, 2017 and 2016, respectively. For additional information regarding our intangible assets, see Note 6 of the Notes to

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

Table of Contents

Methods We Employ to Measure the Fair Value of Goodwill and Related Assets

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount.

Goodwill impairment testing involves estimating the fair value of the associated reporting unit. The fair value of a reporting unit is based on assumptions regarding the future economic prospects of the assets that comprise the reporting unit. These assumptions include (i) discrete financial forecasts for the associated businesses, which, in turn, rely on management's estimates of operating margins, throughput volumes and similar inputs; (ii) long-term growth rates for cash flows beyond the discrete forecast periods; and (iii) appropriate discount rates. If the fair value of a reporting unit (including its inherent goodwill) is less than its carrying value, a non-cash impairment charge to costs and expenses is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2018 and 2017, the carrying value of our goodwill was $5.75 billion.

We did not record any goodwill impairment charges during the three years ended December 31, 2018. For additional information regarding our goodwill, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Use of Estimates for Revenues and Expenses

As noted previously, preparing our consolidated financial statements in conformity with GAAP requires us to make estimates that affect amounts presented in the financial statements. Due to the time required to compile actual billing information and receive third party data needed to record transactions, we routinely employ estimates in connection with revenue and expense amounts in order to meet our accelerated financial reporting deadlines.

Our most significant routine estimates involve certain natural gas processing plant revenues and costs, pipeline transportation revenues, fractionation revenues, marketing revenues and related purchases, and power and utility costs. These types of transactions must be estimated since the actual amounts are generally unavailable at the time we complete our accounting close process. The estimates subsequently reverse in the next accounting period when the corresponding actual customer billing or vendor-invoiced amounts are recorded.

Changes in facts and circumstances may result in revised estimates, which could affect our reported financial statements and accompanying disclosures. Prior to issuing our financial statements, we review our revenue and expense estimates based on currently available information to determine if adjustments are required. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect.

Other Matters

Recent Accounting Developments

For information regarding recent accounting developments involving revenue recognition and leases, see Note 2 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements that have or are reasonably expected to have a material current or future effect on our financial position, results of operations and cash flows.

Historically, operating leases were regarded as off-balance sheet arrangements. On January 1, 2019, we adopted Accounting Standards Codification Topic 842, Leases, which requires long-term leases to be recorded on the balance sheet. Based on current information, we expect to recognize an estimated $250 million of right-of-use assets and corresponding lease liabilities in connection with operating leases. These amounts would represent less than 1% of our total consolidated assets and liabilities, respectively.

Table of Contents

Related Party Transactions

For information regarding our related party transactions, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Insurance

For information regarding insurance matters, see Note 18 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2018 (dollars in millions):

		Payment or Settlement due by Period			
Contractual Obligations	Total	In less than 1 year	In 1-3 years	In 4-5 years	More than 5 years
Scheduled maturities of debt obligations (1)	$26,420.6	$1,500.0	$2,825.0	$2,650.0	$19,445.6
Estimated cash payments for interest (2)	25,520.2	1,190.4	2,195.4	1,980.0	20,154.4
Operating lease obligations (3)	324.8	50.5	84.3	51.7	138.3
Purchase obligations:					
Product purchase commitments (4)	10,273.7	2,558.4	3,980.6	1,823.9	1,910.8
Service payment commitments (5)	403.8	75.1	127.5	92.6	108.6
Capital expenditure commitments (6)	171.8	171.8	--	--	--
Other long-term liabilities (7)	751.6	--	456.2	75.1	220.3
Total contractual payment obligations	$63,866.5	$5,546.2	$9,669.0	$6,673.3	$41,978.0

(1) Represents scheduled future maturities of our current and long-term debt principal obligations. For information regarding our consolidated debt obligations, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.
(2) Estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2018, the contractually scheduled maturities of such balances, and the applicable interest rates. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $2.67 billion in junior subordinated notes (due June 2067 through February 2078). Our estimated cash payments for interest assume that these subordinated notes are not repaid prior to their respective maturity dates. Our estimated cash payments for interest with respect to each junior subordinated note are based on either the current fixed interest rate charged or the weighted-average variable rate paid in 2018, as applicable, for each note applied to the remaining term through the respective maturity date.
(3) Primarily represents land held pursuant to property leases, leases of underground salt dome caverns for the storage of natural gas and NGLs, the lease of transportation equipment used in our operations and office space with affiliates of EPCO.
(4) Represents enforceable and legally binding agreements to purchase goods or services as of December 31, 2018. The estimated payment obligations are based on contractual prices in effect at December 31, 2018 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.
(5) Primarily represents our unconditional payment obligations under firm pipeline transportation contracts.

(6) Represents unconditional payment obligations for services to be rendered or products to be delivered in connection with our capital investment program, including our share of the capital expenditures of unconsolidated affiliates.
(7) As reflected on our consolidated balance sheet at December 31, 2018, “Other long-term liabilities” primarily represent the Liquidity Option Agreement, the noncurrent portion of asset retirement obligations and deferred revenues.

In connection with our acquisition of the EFS Midstream System in 2015, we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for certain producers, over a ten-year period. If constructed, these new assets would be owned by us and be a component of the EFS Midstream System. As of December 31, 2018, we have spent $151 million of the $270 million commitment. Due to the uncertain timing of the remaining potential capital expenditures, we have excluded this amount from the preceding table.

For additional information regarding our significant contractual obligations, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Table of Contents

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

General

In the normal course of our business operations, we are exposed to certain risks, including changes in interest rates and commodity prices. In order to manage risks associated with assets, liabilities and certain anticipated future transactions, we use derivative instruments such as futures, forward contracts, swaps and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

We assess the risk associated with each of our derivative instrument portfolios using a sensitivity analysis model. This approach measures the change in fair value of the derivative instrument portfolio based on a hypothetical 10% change in the underlying interest rates or quoted market prices on a particular day. In addition to these variables, the fair value of each portfolio is influenced by changes in the notional amounts of the instruments outstanding and the discount rates used to determine the present values. The sensitivity analysis approach does not reflect the impact that the same hypothetical price movement would have on the hedged exposures to which they relate. Therefore, the impact on the fair value of a derivative instrument resulting from a change in interest rates or quoted market prices (as applicable) would normally be offset by a corresponding gain or loss on the hedged debt instrument, inventory value or forecasted transaction assuming:

§ the derivative instrument functions effectively as a hedge of the underlying risk;

§ the derivative instrument is not closed out in advance of its expected term; and

§ the hedged forecasted transaction occurs within the expected time period.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. Accordingly, the nature and volume of our derivative instruments may change depending on the specific exposure being managed.

See Note 14 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our derivative instruments and commodity and interest rate hedging activities.

Table of Contents

Commodity Hedging Activities

The prices of natural gas, NGLs, crude oil, petrochemicals and refined products are subject to fluctuations in response to changes in supply and demand, market conditions and a variety of additional factors that are beyond our control. In order to manage such price risks, we enter into commodity derivative instruments such as physical forward contracts, futures contracts, fixed-for-float swaps, basis swaps and option contracts.

The following table summarizes our portfolio of commodity derivative instruments outstanding at December 31, 2018 (volume measures as noted):

Derivative Purpose	Volume (1) Current (2)	Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	4.9	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	1.0	n/a	Cash flow hedge
Octane enhancement:			
Forecasted purchase of NGLs (MMBbls)	1.8	n/a	Cash flow hedge
Forecasted sales of octane enhancement products (MMBbls)	3.1	0.1	Cash flow hedge
Natural gas marketing:			
Natural gas storage inventory management activities (Bcf)	3.3	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	33.6	4.3	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	45.0	1.7	Cash flow hedge
NGLs inventory management activities (MMBbls)	0.3	n/a	Fair value hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	1.0	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	2.0	n/a	Cash flow hedge
Refined products inventory management activities (MMBbls)	0.5	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	18.4	1.9	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	28.5	1.9	Cash flow hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	77.5	0.9	Mark-to-market
NGL risk management activities (MMBbls) (4)	3.3	n/a	Mark-to-market
Refined products risk management activities (MMBbls) (4)	2.6	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	26.3	3.2	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2020, June 2019 and December 2020, respectively.
(3) Current volume includes 29.8 Bcf of physical derivative instruments that are predominantly priced at a marked-based index plus a premium or minus a discount related to location differences.
(4) Reflects the use of derivative instruments to manage risks associated with transportation, processing and storage assets.

At December 31, 2018, our predominant commodity hedging strategies consisted of (i) hedging anticipated future purchases and sales of commodity products associated with transportation, storage and blending activities, (ii) hedging natural gas processing margins and (iii) hedging the fair value of commodity products held in inventory.

§ The objective of our anticipated future commodity purchases and sales hedging program is to hedge the margins of certain transportation, storage, blending and operational activities by locking in purchase and sale prices through the use of derivative instruments and related contracts.

§ The objective of our natural gas processing hedging program is to hedge an amount of earnings associated with these activities. We achieve this objective by executing fixed-price sales for a portion of our expected equity NGL production using derivative instruments and related contracts. For certain natural gas processing contracts, the hedging of expected equity NGL production also involves the purchase of natural gas for shrinkage, which is hedged using derivative instruments and related contracts.

106

Table of Contents

§ The objective of our inventory hedging program is to hedge the fair value of commodity products currently held in inventory by locking in the sales price of the inventory through the use of derivative instruments and related contracts.

Sensitivity Analysis

The following tables show the effect of hypothetical price movements on the estimated fair values of our principal commodity derivative instrument portfolios at the dates indicated (dollars in millions).

The fair value information presented in the sensitivity analysis tables excludes the impact of applying Chicago Mercantile Exchange ("CME") Rule 814, which deems that financial instruments cleared by the CME are settled daily in connection with variation margin payments. As a result of this exchange rule, CME-related derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes; however, the derivatives remain outstanding and subject to future commodity price fluctuations until they are settled in accordance with their contractual terms. Derivative transactions cleared on exchanges other than the CME (e.g., the Intercontinental Exchange or ICE) continue to be reported on a gross basis.

Natural gas marketing portfolio

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2017	December 31, 2018	January 31, 2019
Fair value assuming no change in underlying commodity prices	Asset (Liability)	$(13.9)	$ 7.8	$ 0.6
Fair value assuming 10% increase in underlying commodity prices	Asset (Liability)	(16.9)	8.0	(0.3)
Fair value assuming 10% decrease in underlying commodity prices	Asset (Liability)	(10.8)	7.7	1.5

NGL and refined products marketing, natural gas processing and octane enhancement portfolio

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2017	December 31, 2018	January 31, 2019
Fair value assuming no change in underlying commodity prices	Asset (Liability)	$(76.4)	$ 77.5	$ 37.0
Fair value assuming 10% increase in underlying commodity prices	Asset (Liability)	(126.1)	56.2	35.5
Fair value assuming 10% decrease in underlying commodity prices	Asset (Liability)	(26.8)	98.9	38.6

Crude oil marketing portfolio

		Portfolio Fair Value at		
Scenario	Resulting Classification	December 31, 2017	December 31, 2018	January 31, 2019
Fair value assuming no change in underlying commodity prices	Asset (Liability)	$(65.5)	$ (26.5)	$ 22.1
Fair value assuming 10% increase in underlying commodity prices	Asset (Liability)	(109.4)	(88.6)	(8.9)
Fair value assuming 10% decrease in underlying commodity prices	Asset (Liability)	(21.6)	35.6	53.2

Supplemental Information regarding Unrealized Gains (Losses)

In the aggregate, the fair value of our commodity hedging portfolios at December 31, 2018 was a net derivative asset of $58.8 million prior to the impact of CME Rule 814. This amount is comprised of $118.8 million of net deferred hedge gains attributable to cash flow hedges partially offset by aggregate net unrealized losses of $60.0 million attributable to fair value hedges and mark-to-market derivative instruments. The following table reflects how the net unrealized loss at December 31, 2018 will impact future earnings in the periods indicated (dollars in millions):

Net unrealized loss at December 31, 2018	$(60.0)
Reversal of net unrealized loss (recognized as net unrealized mark-to-market gains) by period:	
Calendar year 2019:	
First quarter	11.1
Second quarter	22.1
Third quarter	19.8
Fourth quarter	4.9
Total 2019	57.9
Calendar year 2020	2.1
Total net unrealized mark-to-market gains	60.0
Total impact on earnings	$--

107

Table of Contents

As the unrealized mark-to-market gains attributable to the financial hedges are recognized in earnings, the corresponding actual losses on the financial hedges and related gains on the physical transactions will be simultaneously realized.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy may be used in controlling our overall cost of capital associated with such borrowings. The composition of our derivative instrument portfolios may change depending on our hedging requirements. We have no interest rate hedging instruments outstanding as of the filing date of this annual report.

Product Purchase Obligations

We have long-term purchase commitments for natural gas, NGLs, crude oil, petrochemicals and refined products. For additional information regarding these commitments, see Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Our audited consolidated financial statements begin on page F-1 of this annual report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

Table of Contents

ITEM 9A. CONTROLS AND PROCEDURES.

Disclosure Controls and Procedures

As of the end of the period covered by this annual report, our management carried out an evaluation, with the participation of (i) A. James Teague, our general partner's Chief Executive Officer and (ii) W. Randall Fowler, our general partner's President and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Mr. Teague is our principal executive officer and Mr. Fowler is our principal financial officer. Based on this evaluation, as of the end of the period covered by this annual report, Messrs. Teague and Fowler concluded:

(i) that our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our principal executive and financial officers, as appropriate to allow for timely decisions regarding required disclosures; and

(ii) that our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) during the fourth quarter of 2018, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Section 302 and 906 Certifications

The required certifications of Messrs. Teague and Fowler under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 are included as exhibits to this annual report (see Exhibits 31 and 32 under Part IV, Item 15 of this annual report).

Table of Contents

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL
OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2018

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its Chief Executive Officer and its President and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended. Our internal control system was designed to provide reasonable assurance to the management of Enterprise Products Partners L.P. and the Board of Directors of its general partner regarding the preparation and fair presentation of Enterprise Products Partners L.P.'s published financial statements.

Our management assessed the effectiveness of Enterprise Products Partners L.P.'s internal control over financial reporting as of December 31, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control—Integrated Framework (2013). This assessment included a review of the design and operating effectiveness of internal controls over financial reporting as well as the safeguarding of assets. Based on our assessment, we believe that, as of December 31, 2018, Enterprise Products Partners L.P.'s internal control over financial reporting is effective based on those criteria.

Our Audit and Conflicts Committee is comprised of independent directors who are not officers or employees of our general partner. This committee meets regularly with members of management, internal audit staff and representatives of Deloitte & Touche LLP, which is our independent registered public accounting firm, to discuss the adequacy of Enterprise Products Partners L.P.'s internal controls over financial reporting, consolidated financial statements and the nature, extent and results of the audit effort. Management reviews all of Enterprise Products Partners L.P.'s significant accounting policies and assumptions that affect its results of operations with the Audit and Conflicts Committee. Both the independent registered public accounting firm and our internal auditors have direct access to the Audit and Conflicts Committee without the presence of management.

Deloitte & Touche LLP has issued its attestation report regarding our internal control over financial reporting. That report is included within this Part II, Item 9A (see "Report of Independent Registered Public Accounting Firm").

Pursuant to the requirements of Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934, as amended, this annual report on Internal Control Over Financial Reporting has been signed below by the following persons on behalf of the registrant and in their respective capacities indicated below on March 1, 2019.

/s/ A. James Teague	/s/ W. Randall Fowler
Name: A. James Teague	Name: W. Randall Fowler
Title: Chief Executive Officer of Enterprise Products Holdings LLC	Title: President and Chief Financial Officer of Enterprise Products Holdings LLC

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the “Company”) as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the criteria established in Internal Control—Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements as of and for the year ended December 31, 2018, of the Company and our report dated March 1, 2019, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management’s Annual Report on Internal Control over Financial Reporting as of December 31, 2018. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2019
111

Table of Contents

ITEM 9B. OTHER INFORMATION.

On February 26, 2019, Enterprise GP executed Amendment No. 4 to our partnership agreement in response to changes to the Internal Revenue Code enacted by the Bipartisan Budget Act of 2015 relating to partnership audit and adjustment procedures. The foregoing description of the Amendment No. 4 to the partnership agreement is qualified in its entirety by reference to the full text of the amendment, which is filed as Exhibit 3.7 hereto and incorporated by reference herein.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND PARTNERSHIP GOVERNANCE.

Partnership Management

General

The following individuals currently serve as members of the Board of Enterprise GP: Richard H. Bachmann, Carin M. Barth, Murray E. Brasseux, W. Randall Fowler, James T. Hackett, Charles E. McMahen, William C. Montgomery, John R. Rutherford, Richard S. Snell, A. James Teague, Harry P. Weitzel and Randa Duncan Williams. Ms. Duncan Williams serves as the non-executive Chairman of the Board, and Mr. Bachmann serves as the non-executive Vice Chairman of the Board. Messrs. Brasseux and Rutherford joined the Board in January 2019.

In addition, Dr. Ralph S. Cunningham, Larry J. Casey and Edwin C. Smith serve as “advisory directors” for Enterprise GP, and O.S. Andras serves as an “honorary director.” Dr. Cunningham joined as an advisory director in January 2019. Service as an advisory or honorary director does not confer any of the rights, obligations, liabilities or responsibilities of a director of Enterprise GP (including any power or authority to vote on any matters as a director).

As is commonly the case with publicly traded limited partnerships, we do not directly employ any of the persons responsible for our management, administrative or operating functions. Pursuant to the ASA with EPCO, these roles are performed by employees of EPCO, which are under the direction of the Board and executive officers of Enterprise GP. The executive officers of Enterprise GP are elected for one-year terms and may be removed, with or without cause, only by the Board. Our unitholders do not elect the officers or directors of Enterprise GP. The DD LLC Trustees, through their control of Enterprise GP, have the ability to elect, remove and replace at any time, all of the officers and directors of our general partner. Each member of the Board of Enterprise GP serves until such member’s death, resignation or removal. The employees of EPCO who served as directors of our general partner during 2018 were Ms. Duncan Williams and Messrs. Bachmann, Fowler, Teague and Weitzel.

Notwithstanding any contractual limitation on its obligations or duties, Enterprise GP is liable for all debts we incur (to the extent not paid by us), except to the extent that such indebtedness or other obligations are non-recourse to Enterprise GP. Whenever possible, Enterprise GP intends to make any such indebtedness or other obligations non-recourse to itself.

Under our limited partnership agreement and subject to specified limitations, we will indemnify to the fullest extent permitted by Delaware law, from and against all losses, claims, damages or similar events, any director or officer, or while serving as director or officer, any person who is or was serving as a tax matters member or as a director, officer, tax matters member, employee, partner, manager, fiduciary or trustee of our partnership or any of our affiliates.

Additionally, we will indemnify to the fullest extent permitted by law, from and against all losses, claims, damages or similar events, any person who is or was an employee (other than an officer) or agent of our general partner.

Table of Contents

Office of the Chairman

The Office of the Chairman is a management oversight group comprised of four individuals: Ms. Duncan Williams (as Chairman of the Board), Mr. Bachmann (as Vice Chairman of the Board), Mr. Teague (as Chief Executive Officer ("CEO")) and Mr. Fowler (as President and Chief Financial Officer ("CFO")). The purpose of the Office of the Chairman is for the group to serve collectively as a liaison between the Board and senior management with respect to, and to provide the Chairman, Vice-Chairman, CEO, and President/CFO a venue to discuss, certain matters including:

§ the strategic direction of Enterprise (including business opportunities through organic growth and acquisitions);

§ the vision, leadership and development of the management team;

§ business goals and operational performance; and

§ strategies to preserve our financial strength.

In addition, the Office of the Chairman assists the Board and its Governance Committee in identifying director education opportunities and in determining the size and composition of the Board and recruitment of new members. The Office of the Chairman also oversees policies that (i) reflect our values and business goals and (ii) enhance the effectiveness of our governance structure. The Office of the Chairman also collectively oversees and provides strategic direction for our legal and human resources departments.

In her role as Chairman of the Board (a non-executive role), Ms. Duncan Williams is responsible for, among other things: (i) presiding over and setting the agendas for meetings of the Board, with due consideration of our values and business goals and an effective governance structure; (ii) overseeing the appropriate flow of information to the Board; (iii) acting as a liaison between the Board and senior management; and (iv) meeting regularly with the Board to review our strategic direction.

In his role as Vice Chairman of the Board (a non-executive role), Mr. Bachmann is responsible for, among other things: (i) assisting the Chairman of the Board in the execution of the Chairman of the Board's functions and responsibilities, as requested from time to time by the Chairman of the Board; and (ii) meeting regularly with the Board to review our strategic direction.

In his role as CEO, Mr. Teague is our principal executive officer and is responsible for, among other things: (i) managing our overall business strategy and day-to-day operations; (ii) overseeing and providing strategic direction for us, subject to Board approval, in the areas of operations, commercial activities, business development, and health and safety; and (iii) providing the required certifications as principal executive officer of Enterprise GP in connection with our disclosure controls and procedures and internal control over financial reporting.

In his role as President and CFO, Mr. Fowler is our principal financial officer and is responsible for, among other things: (i) managing our overall financial strategy; (ii) overseeing and providing strategic direction for us, subject to Board approval, in the areas of accounting, risk management, finance, treasury and cash management, information technology, investor relations, and public relations and (iii) providing the required certifications as principal financial officer of Enterprise GP in connection with our disclosure controls and procedures and internal control over financial reporting.

Table of Contents

Directors and Executive Officers of Enterprise GP

The following table sets forth the name, age and position of each of the directors, excluding advisory or honorary directors, and executive officers of Enterprise GP at March 1, 2019. Each executive officer holds the same respective office shown below in the managing member of EPO.

Name	Age	Position with Enterprise GP
Randa Duncan Williams (1,2,6)	57	Director and Chairman of the Board
Richard H. Bachmann (1,6)	66	Director and Vice Chairman of the Board
A. James Teague (1,6,7,8)	73	Director and CEO
W. Randall Fowler (1,6,7,8)	62	Director, President and CFO
Carin M. Barth (2,6)	56	Director
Murray E. Brasseux (4)	69	Director
James T. Hackett (2,3,6)	65	Director
Charles E. McMahen (4,5)	79	Director
William C. Montgomery (4)	57	Director
John R. Rutherford (4)	58	Director
Richard S. Snell (4,6)	76	Director
Harry P. Weitzel (6,8)	54	Director and Senior Vice President, General Counsel and Secretary
Graham W. Bacon (8)	55	Executive Vice President (Operations and Engineering)
William Ordemann (8)	59	Executive Vice President (Strategy Development and Implementation)
R. Daniel Boss (8)	43	Senior Vice President (Accounting and Risk Control)
Brent B. Secrest (8)	46	Senior Vice President (Commercial)
Michael W. Hanson (8)	51	Vice President and Principal Accounting Officer

(1) Member of Office of the Chairman
(2) Member of the Governance Committee
(3) Chairman of the Governance Committee
(4) Member of the Audit and Conflicts Committee
(5) Chairman of the Audit and Conflicts Committee
(6) Member of the Capital Projects Committee
(7) Co-Chairman of the Capital Projects Committee
(8) Executive officer

The following information presents a brief history of the business experience of our directors and executive officers:

Randa Duncan Williams

Ms. Duncan Williams was elected Chairman of the Board of Enterprise GP in February 2013 and a director of Enterprise GP in November 2010. She was elected Chairman of EPCO in May 2010, having previously served as Group Co-Chairman since 1994. Ms. Duncan Williams has served as a member of Enterprise GP's Governance Committee since April 2014 and Capital Projects Committee since November 2016.

Ms. Duncan Williams has served as a director of EPCO since February 1991. She also served as a director of the general partner of Enterprise GP Holdings L.P. ("Holdings GP") from May 2007 to November 2010.

Prior to joining EPCO in 1994, Ms. Duncan Williams practiced law with the firms Butler & Binion and Brown, Sims, Wise & White. Ms. Duncan Williams previously served on the board of directors of Encore Bancshares from July 2007 until July 2012. She currently serves on the board of trustees for numerous charitable organizations. Ms.

Duncan Williams is the daughter of the late Mr. Dan L Duncan, our founder.

114

Table of Contents

Richard H. Bachmann

Mr. Bachmann was elected a director and Vice Chairman of the Board of Enterprise GP in January 2016 and has served as a member of its Capital Projects Committee since November 2016. He previously served as a director of Enterprise GP from November 2010 through April 2014.

Mr. Bachmann was elected President and CEO of EPCO in May 2010 and has served as a director since January 1999. He previously served as Secretary of EPCO from May 1999 to May 2010 and as a Group Vice Chairman of EPCO from December 2007 to May 2010.

Mr. Bachmann served as an Executive Vice President of Holdings GP from April 2005 to November 2010 and as a director of Holdings GP from February 2006 to November 2010. He served as Chief Legal Officer and Secretary of Holdings GP from April 2005 to May 2010. Mr. Bachmann served as Executive Vice President and Chief Legal Officer of Enterprise Products GP, LLC ("EPGP," the former general partner of Enterprise) from February 1999 until November 2010 and as Secretary of EPGP from November 1999 to November 2010. He previously served as a director of EPGP from June 2000 to January 2004 and from February 2006 to May 2010. Mr. Bachmann served as a director of DEP Holdings, LLC ("DEP GP"), the general partner of Duncan Energy Partners L.P., from October 2006 to May 2010 and as President and CEO of DEP GP from October 2006 to April 2010.

A. James Teague

Mr. Teague was elected CEO of Enterprise GP in January 2016 and has been a director of Enterprise GP since November 2010. Mr. Teague previously served as the Chief Operating Officer ("COO") of Enterprise GP from November 2010 to December 2015 and served as an Executive Vice President of Enterprise GP from November 2010 until February 2013. He has served as Co-Chairman of the Capital Projects Committee of Enterprise GP since November 2016.

Mr. Teague served as an Executive Vice President of EPGP from November 1999 to November 2010 and additionally as a director from July 2008 to November 2010 and as COO from September 2010 to November 2010. In addition, he served as Chief Commercial Officer of EPGP from July 2008 until October 2010. He served as Executive Vice President and Chief Commercial Officer of DEP GP from July 2008 until September 2011. He previously served as a director of DEP GP from July 2008 to May 2010 and as a director of Holdings GP from October 2009 to May 2010.

Mr. Teague joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. From 1998 to 1999, Mr. Teague served as President of Tejas Natural Gas Liquids, LLC, then an affiliate of Shell. From 1997 to 1998, he was President of Marketing and Trading for MAPCO, Inc. Mr. Teague also serves on the board of directors of Solaris Oilfield Infrastructure, Inc.

W. Randall Fowler

Mr. Fowler was elected a director of Enterprise GP in September 2011 and has served as its President since January 2016, having previously served as Chief Administrative Officer from April 2015 to January 2016. Mr. Fowler has served as CFO of Enterprise GP since August 2018, having previously served as Executive Vice President and CFO of Enterprise GP from November 2010 to March 2015 and as Executive Vice President and CFO of EPGP from August 2007 to November 2010. He has served as Co-Chairman of the Capital Projects Committee of Enterprise GP since November 2016.

Mr. Fowler was elected Vice Chairman and CFO of EPCO in May 2010. He previously served as President and CEO of EPCO from December 2007 to May 2010 and as its CFO from April 2005 to December 2007.

Mr. Fowler also served as President and CEO of DEP GP from April 2010 until September 2011 and as Executive Vice President and CFO of DEP GP from August 2007 to April 2010. He served as a director of DEP GP from September 2006 until September 2011. Mr. Fowler served as Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and of DEP GP from October 2006 to August 2007. Mr. Fowler also previously served as a director of EPGP and of Holdings GP from February 2006 to May 2010. Mr. Fowler also served as Senior Vice President and CFO of Holdings GP from August 2005 to August 2007.

Table of Contents

Mr. Fowler, a Certified Public Accountant (inactive), joined Enterprise as Director of Investor Relations in January 1999. He also serves as Chairman of the Board of the Master Limited Partnership Association (formerly National Association of Publicly Traded Partnerships). Mr. Fowler is on the Advisory Board of Alerian, an independent provider of market intelligence for master limited partnerships ("MLPs"), which includes its benchmark Alerian MLP Index , or AMZ. He also serves on the Advisory Board for the College of Business at Louisiana Tech University.

Carin M. Barth

Ms. Barth was elected a director of Enterprise GP in October 2015. She has served as a member of its Governance Committee since October 2015 and its Capital Projects Committee since November 2016.

Ms. Barth is co-founder and President of LB Capital Inc., a private equity investment firm established in 1988. She currently serves on the following boards of directors: Black Stone Minerals, L.P., where she is Chair of the Audit Committee and Group 1 Automotive, Inc. Additionally, she is Chairman of the Investment Advisory Committee for the Endowment at Texas Tech University, Chairman of The Welch Foundation and a board member of the Ronald McDonald House of Houston.

Ms. Barth previously served on the Housing Commission at the Bi-Partisan Policy Center in Washington, DC from 2011 to 2014, and was a Commissioner of the Texas Department of Public Safety from 2008 to 2014. She also served as a board member of the following: Bill Barrett Corporation from June 2012 to May 2016; Western Refining Inc., where she was Chair of the Audit Committee from March 2006 to January 2016; Methodist Hospital Research Institute from 2007 to 2012; Encore Bancshares, Inc. from 2009 to 2012; Amegy Bancorporation, Inc. from 2006 to 2009; the Texas Public Finance Authority from 2006 to 2008; and the Texas Tech University System Board of Regents from 1999 to 2005. She was appointed by President George W. Bush to serve as CFO of the U.S. Department of Housing and Urban Development from 2004 to 2005.

Murray E. Brasseux

Mr. Brasseux was elected a director of Enterprise GP and a member of its Audit and Conflicts Committee in January 2019.

Mr. Brasseux is also a member of the board of directors of Adams Resources & Energy, Inc., a publicly-traded company primarily engaged in the business of crude oil marketing and tank truck transportation of liquid and dry bulk chemicals. Mr. Brasseux retired from Compass Bank in December 2014 after 20 years of service, having most recently served as Managing Director of Oil & Gas Finance. Mr. Brasseux also served as a consultant to Compass Bank from January 2015 to June 2015 and as a consultant to Loughlin Management Partners (a restructuring and advisory firm) from June 2015 to December 2017. Mr. Brasseux also serves on the board of the Rare Book School (an affiliate of the University of Virginia).

James T. Hackett

Mr. Hackett was elected a director of Enterprise GP in April 2014. He has served as a member of its Governance Committee since April 2014, including in the role of committee Chairman since November 2016. In addition, Mr. Hackett has served as a member of Enterprise GP's Capital Projects Committee since November 2016.

Mr. Hackett is a senior advisor with Riverstone Holdings LLC, a private energy investment firm. Mr. Hackett serves as Executive Chairman and Interim CEO of Alta Mesa Resources, Inc. (formerly named Silver Run Acquisition Corporation II) and CEO and President of Kingfisher Midstream, LLC, an affiliate of Alta Mesa engaged in providing certain midstream energy services, including crude oil and gas gathering, processing and marketing to producers of natural gas, natural gas liquids, crude oil and condensate.

Mr. Hackett served as Executive Chairman of the board of directors of Anadarko Petroleum Corporation ("Anadarko"), an independent oil and natural gas exploration and production company, from 2012 to 2013 after serving as its CEO from 2003 to 2012 and Chairman of the Board from 2006 to 2012. He also served as Anadarko's President from 2003 to 2010. Mr. Hackett is a board member of Flour Corp. and NOV, Inc. as well as Sierra Oil & Gas and Talen Energy (portfolio companies of Riverstone). He is a former director of Bunge Ltd. and the former

Table of Contents

Chairman of the Board of the Federal Reserve Bank of Dallas. He is a past Chairman of the National Petroleum Council, a member of the Society of Petroleum Engineers, a member of the Baylor College of Medicine Board of Trustees and a member of the Rice University Board of Trustees. Mr. Hackett also currently serves as a faculty member at The University of Texas (Austin).

Charles E. McMahen

Mr. McMahen was elected a director of Enterprise GP in November 2010 and has served as Chairman of its Audit and Conflicts Committee since November 2010.

Mr. McMahen also serves as a director for BBVA Compass Bancshares, Inc. (a wholly owned subsidiary of BBVA and a bank holding company for BBVA's North American banking operations). He serves on the Audit Committee for BBVA Compass Bancshares, Inc. and as Chairman of its Risk Committee.

Mr. McMahen served as a director of Holdings GP from August 2005 to November 2010. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and CEO of Compass Banks of Texas from March 1990 until March 1999. Mr. McMahen has served as a director of Compass Bancshares, and its successor, BBVA Compass Bank (a wholly owned subsidiary of BBVA), since 2001. Mr. McMahen served as Chairman of the Board of Regents of the University of Houston from September 1998 to August 2000.

William C. Montgomery

Mr. Montgomery was elected a director of Enterprise GP and appointed a member of its Audit and Conflicts Committee in October 2015.

Mr. Montgomery has served as a Partner of Quantum Energy Partners since 2011 and is also a member of its Executive and Investment Committees. He is responsible for originating and overseeing investments in the oil and gas upstream and oilfield service sectors. Mr. Montgomery also serves on the board of Apache Corporation.

Prior to joining Quantum Energy Partners, Mr. Montgomery was a Partner in the Investment Banking Division of Goldman, Sachs & Co. where, during his tenure, he headed the firm's Americas Natural Resources Group as well as its Houston office. His career as a banker spanned 22 years and was focused on large cap energy companies primarily in the upstream and oil service sectors. Mr. Montgomery has been an active civic leader, chairing the boards of The Houston Museum of Natural Science and The St. Francis Episcopal Day School and currently serves on the board of trustees of The Kinkaid School, The Episcopal Health Foundation and the Board of Visitors of the MD Anderson Cancer Center.

John R. Rutherford

Mr. Rutherford was elected a director of Enterprise GP and appointed a member of its Audit and Conflicts Committee in January 2019.

Mr. Rutherford currently serves as the Executive Director of the Coalition for a Fair and Open Port, an ad hoc voluntary unincorporated nonprofit association of energy industry entities whose business operations depend on open and fair access to the Houston Ship Channel. Mr. Rutherford also serves as a Senior Managing Director of NRI Energy Partners LLC, a firm that evaluates and invests in private and public energy companies and provides financial and strategic consulting services to energy companies and investment firms.

Mr. Rutherford previously served as Executive Vice President (Strategic Planning, M&A and Business Development) of the general partner of Plains All American Pipeline, L.P. ("Plains") and as a member of Plains' executive committee from October 2010 through July 2015. Mr. Rutherford also served as a financial consultant to Plains from July 2015 through September 2018. His career includes over 20 years of investment banking experience as a mergers and acquisitions and strategic advisor to public and private energy companies, investment firms, management teams and boards of directors. Prior to joining Plains, Mr. Rutherford served as Managing Director of the North American Energy

Table of Contents

Practice of Lazard Freres & Company from 2007 until 2010. Prior to joining Lazard, he was a partner at Simmons & Company for over ten years.

Richard S. Snell

Mr. Snell was elected a director of Enterprise GP and appointed a member of its Audit and Conflicts Committee in September 2011. He has served as a member of its Capital Projects Committee since November 2016.

Mr. Snell is a Certified Public Accountant and is of counsel with the law firm of Ytterberg Deery Knull LLP, having been with the firm since January 2017. He previously served as an attorney with the law firms of Thompson & Knight LLP (from 2000 to early 2017) and Snell & Smith, P.C. (from its founding in 1993 until 2000).

Mr. Snell served as a director of DEP GP from January 2010 to September 2011 and as a director of the general partner of TEPPCO Partners, L.P. from January 2006 until October 2009. From June 2000 until February 2006, he served as a director of EPGP.

Harry P. Weitzel

Mr. Weitzel was elected a director of Enterprise GP and appointed a member of its Capital Projects Committee in November 2016 and has served as Senior Vice President, General Counsel and Secretary of Enterprise GP since April 2016. He previously served as Senior Vice President, Deputy General Counsel and Secretary of Enterprise GP from January 2015 to April 2016. Mr. Weitzel is responsible for all legal functions of Enterprise, including securities, litigation, employment, mergers and acquisitions, corporate governance and commercial transactions.

Mr. Weitzel has extensive experience as a commercial litigator, having practiced over 24 years in Texas and California. He has successfully represented individual, corporate and governmental clients as plaintiffs and defendants in a wide variety of business-related matters. Mr. Weitzel has tried cases in state and federal courts, as well as arbitrations under the American Arbitration Association, JAMS and the International Chamber of Commerce. He has handled appeals in state and federal courts. Prior to joining Enterprise, Mr. Weitzel was a commercial litigation partner with Pepper Hamilton LLP in Irvine, California from October 2009 to December 2014.

Graham W. Bacon

Mr. Bacon was elected Executive Vice President (Operations and Engineering) of Enterprise GP in October 2015. He previously served as Group Senior Vice President (Operations and Environmental, Health, Safety & Training) from February 2014 to October 2015; as Senior Vice President (Operations) from January 2012 to February 2014; as Vice President (Operations) from June 2006 to January 2012, and as Vice President (Engineering) from September 2005 to May 2006. He joined Enterprise in 1991 and has held a variety of operations and engineering roles. Prior to joining Enterprise, Mr. Bacon worked for Vista Chemical Company.

William Ordemann

Mr. Ordemann has served as Executive Vice President (Strategy Development and Implementation) of Enterprise GP since April 2018, having previously served as Executive Vice President (Commercial) from October 2015 to April 2018. He served as Group Senior Vice President (Unregulated Liquids, Crude and Natural Gas Services) from April 2012 to October 2015. He served as Executive Vice President of Enterprise GP from August 2007 to April 2012.

Mr. Ordemann served as COO of EPGP from August 2007 until September 2010 and as its Executive Vice President from August 2007 to November 2010. Mr. Ordemann previously served as a Senior Vice President of EPGP from

September 2001 to August 2007 and was a Vice President of EPGP from October 1999 to September 2001. He also served as an Executive Vice President of DEP GP from August 2007 until September 2011 and as a director of Oiltanking GP from October 2014 until February 2015.

Mr. Ordemann joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. He is also a director of the GPA Midstream Association, where he serves on the Executive Committee currently as Chairman.

Table of Contents

R. Daniel Boss

Mr. Boss, a Certified Public Accountant, was elected Senior Vice President (Accounting and Risk Control) of Enterprise GP in August 2016. He is responsible for the overall leadership of our Accounting and Risk Control organizations.

Mr. Boss served as a Senior Vice President of Enterprise GP from March 2015 to August 2016 with responsibility over our regulated business. He also served as Vice President (Risk Control) from April 2013 to March 2015 and as Senior Director (Risk Control) from January 2010 to March 2013. While serving in these positions, Mr. Boss was Chairman of the Risk Management Committee and had responsibilities for our marketing risk management policies, transaction controls and derivatives and hedging strategies compliance. Mr. Boss also served as Director (Volume Accounting) from November 2008 until January 2010 where he was responsible for gas marketing and commodity derivatives accounting, hedging and reporting.

Prior to joining Enterprise, Mr. Boss held leadership positions with Merrill Lynch Commodities and Dynegy Inc.

Brent B. Secrest

Mr. Secrest has served as Senior Vice President (Commercial) of Enterprise GP since July 2018. He has commercial responsibility for NGL, crude oil and refined products marketing, NGL assets and terminals, crude oil assets and terminals and Enterprise’s trucking and marine businesses.

Mr. Secrest previously served as Senior Vice President (Liquid Hydrocarbons Marketing) of Enterprise GP from May 2016 to June 2018, as Vice President (Crude Oil and Refined Products Marketing) from October 2015 to May 2016 and as Vice President (Crude Oil Pipelines and Terminals) from October 2012 to October 2015. He has also served Enterprise in various other leadership positions, including in the areas of NGL marketing and supply, commercial development, distribution, and business analysis. Mr. Secrest has over 20 years of experience in the energy industry and began his career at Basis Petroleum Inc. prior to joining Enterprise in 1996.

Michael W. Hanson

Mr. Hanson was elected a Vice President of Enterprise GP in April 2011 and its Principal Accounting Officer in August 2016. His responsibilities include team leadership in financial and management reporting matters, including the preparation of Enterprise’s quarterly and annual reports. Mr. Hanson reports to Mr. Boss, who has overall leadership of the Accounting department.

Mr. Hanson has served Enterprise and its affiliates in various accounting roles since 1992, including as an Assistant Controller from April 2007 to July 2016 and Director of Financial Reporting from November 2004 to March 2007.

Table of Contents

Director Experience, Qualifications, Attributes and Skills

The following is a brief discussion of the experience, qualifications, attributes or skills that led to the conclusion that each of the following persons should serve as a director of our general partner.

Five of our directors are current employees of EPCO and officers of our general partner or its affiliates. Each of these directors has significant experience in our industry as executive officers as well as other qualifications, attributes and skills. These include:

§ for Ms. Duncan Williams, legal and community involvement with numerous charitable organizations, and active involvement in EPCO's businesses, including ownership in and management of our businesses;

§ for Mr. Teague, over 40 years of commercial management of midstream assets and marketing and trading activities, both for third parties and for us;

§ for Mr. Fowler, 20 years of experience with our midstream assets, including finance, accounting and investor relations and, for over the last ten years, as a member of our executive management team;

§ for Mr. Bachmann, over 30 years of experience with our midstream assets, including legal, regulatory, contracts and mergers and acquisitions and, for approximately 20 years, as a member of either EPCO's or our executive management teams; and

§ for Mr. Weitzel, over 25 years of experience in Texas and California as a commercial litigator, having successfully represented individual, corporate and governmental clients as plaintiffs and defendants in a wide variety of business-related matters.

Our seven outside voting directors also have significant experience in a variety of capacities, as well as other qualifications, attributes and skills. These include:

§ for Ms. Barth, executive management experience in various financial and governance roles;

§ for Mr. Brasseux, executive management experience in banking and finance as well as governance roles;

§ for Mr. Hackett, executive management of a major oil and gas exploration and production company;

§ for Mr. McMahen, executive management experience in banking and finance;

§ for Mr. Montgomery, executive management of both an investment banking firm and a private equity investment firm serving the global energy industry;

§ for Mr. Rutherford, executive management experience in the midstream energy industry (including in the areas of strategic planning, mergers and acquisitions, investment banking and finance); and

§ for Mr. Snell, professional experience involving complex legal and accounting matters.

As advisory directors, Dr. Cunningham has a long history with Enterprise and its operations, Mr. Casey has executive management experience in NGL and petrochemicals trading and related storage businesses and Mr. Smith has experience in banking and investment matters. As an honorary director, Mr. Andras has a long history with Enterprise and its operations, including being a former CEO.

Partnership Governance

We are committed to sound principles of governance. Such principles are critical for us to achieve our performance goals and maintain the trust and confidence of investors, employees, suppliers, business partners and other stakeholders.

Table of Contents

A key element of strong governance is having independent members of the Board. Pursuant to the NYSE listing standards, a director will be considered independent if the Board determines that he or she does not have a material relationship with Enterprise GP or us (either directly or as a partner, unitholder or officer of an organization that has a material relationship with Enterprise GP or us). Based on the foregoing, the Board has affirmatively determined that Ms. Barth and Messrs. Brasseux, Hackett, McMahen, Montgomery, Rutherford and Snell are independent directors under the NYSE rules.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain NYSE rules. In particular, we are not required to comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of Enterprise GP be comprised of a majority of independent directors. Currently, seven of the twelve Board members of Enterprise GP are independent under NYSE rules; however, this composition may not always be in effect. Also, we have elected to not comply with Sections 303A.04 and 303A.05 of the NYSE Listed Company Manual, which would require that the Board of Enterprise GP maintain a Nominating Committee and a Compensation Committee, each consisting entirely of independent directors.

Code of Conduct and Ethics and Corporate Governance Guidelines

Enterprise GP has adopted a "Code of Conduct" that applies to its directors, officers and employees. This code sets forth our requirements for compliance with legal and ethical standards in the conduct of our business, including general business principles, legal and ethical obligations, compliance policies for specific subjects, obtaining guidance on complying with the code, the reporting of compliance issues, and discipline for violations of the code. The Code of Conduct also establishes policies applicable to our CEO, President and CFO, Principal Accounting Officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications, and prompt internal reporting of violations of the code (and thus accountability for adherence to the code). Employees are required to certify their understanding and compliance with the Code of Conduct on an annual basis. Training on Code of Conduct is also provided to employees, where applicable.

Governance guidelines, together with applicable committee charters, provide the framework for effective governance of our partnership. The Board has adopted the "Governance Guidelines of Enterprise Products Partners," which address several matters, including qualifications for directors, responsibilities of directors, retirement of directors, the composition and responsibilities of the Audit and Conflicts Committee and the Governance Committee, the conduct and frequency of Board and committee meetings, management succession plans, director access to management and outside advisors, director compensation, director and executive officer equity ownership, director orientation and continuing education, and annual self-evaluation of the Board. The Board recognizes that effective governance is an on-going process, and thus, it will review the Governance Guidelines of Enterprise Products Partners annually or more often as deemed necessary.

Audit and Conflicts Committee

The purpose of the Board's Audit and Conflicts Committee is to address audit and conflicts-related matters. In accordance with NYSE rules and the Securities Exchange Act of 1934, the Board has named five of its members to serve on the Audit and Conflicts Committee. Members of the Audit and Conflicts Committee must have a basic understanding of finance and accounting matters and be able to read and understand fundamental financial statements, and at least one member of the Audit and Conflicts Committee shall have accounting or related financial management expertise. The current members of the Audit and Conflicts Committee are Messrs. Brasseux, McMahen, Montgomery, Rutherford and Snell, all of whom are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment. The Board has affirmatively determined that Mr. McMahen satisfies the definition of “Audit Committee Financial Expert” as that term is defined in Item 407(d)(5) of Regulation S-K promulgated by the SEC.

Table of Contents

The primary responsibilities of the Audit and Conflicts Committee include (i) reviewing potential conflicts of interest, including related party transactions, (ii) monitoring the integrity of our financial reporting process and related systems of internal control, (iii) ensuring our legal and regulatory compliance and that of Enterprise GP, (iv) overseeing the independence and performance of our independent public accountant, (v) approving all services performed by our independent public accountant, (vi) providing for an avenue of communication among the independent public accountant, management, internal audit function and the Board, (vii) encouraging adherence to and continuous improvement of our policies, procedures and practices at all levels, (viii) reviewing areas of potential significant financial risk to our businesses and (ix) approving awards granted under long-term incentive plans.

If the Board believes that a particular matter presents a conflict of interest and proposes a resolution, the Audit and Conflicts Committee has the authority to review such matter to determine if the proposed resolution is fair and reasonable to us. Any matters approved by the Audit and Conflicts Committee are conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by Enterprise GP or the Board of any duties they may owe us or our unitholders.

Pursuant to its formal written charter, the Audit and Conflicts Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. The Audit and Conflicts Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Governance Committee

The primary purpose of the Governance Committee is to develop and recommend to the Board a set of governance guidelines applicable to our partnership, to review such guidelines from time to time and to oversee governance matters related to our business, including Board and Committee composition, qualifications of Board candidates, director independence, succession planning and related matters. The Governance Committee also assists in Board oversight of management's establishment and administration of our environmental, safety and transportation compliance policies, procedures, programs and initiatives, and related matters. In accordance with its charter, the Governance Committee shall be composed of not less than three members, at least a majority of whom shall be independent directors. Currently, the Governance Committee is comprised of Ms. Duncan Williams and two independent directors (Ms. Barth and Mr. Hackett).

Like the Audit and Conflicts Committee, the Governance Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to our independent public accountants as well as any EPCO personnel whom it deems necessary in fulfilling its responsibilities. In addition, the Governance Committee has the ability to retain, at our expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties.

Capital Projects Committee

The primary purpose of the Capital Projects Committee is to review and approve certain expenditures by Enterprise GP, Enterprise and/or their respective consolidated subsidiaries in connection with proposed capital projects. Currently, the Capital Projects Committee is comprised of Ms. Duncan Williams, Ms. Barth and Messrs. Bachmann, Fowler, Hackett, Snell, Teague and Weitzel. Messrs. Teague and Fowler are co-chairmen of the Capital Projects Committee.

Investor Access to Corporate Governance Information

We provide investors access to information relating to our governance procedures and principles, including the Code of Conduct, Governance Guidelines, the charters of the Audit and Conflicts Committee, the Governance Committee and the Capital Projects Committee, along with other information, through our website, www.enterpriseproducts.com. You may also contact our Investor Relations department at (866) 230-0745 for printed copies of these documents free of charge.

Table of Contents

NYSE Corporate Governance Listing Standards

On March 6, 2018, Mr. Teague certified to the NYSE (as required by Section 303A.12(a) of the NYSE Listed Company Manual) that he was not aware of any violation by us of the NYSE's Corporate Governance listing standards as of that date.

Executive Sessions of Non-Management Directors

The Board holds regular executive sessions in which non-management directors meet without any members of management present. The purpose of these executive sessions is to promote open and candid discussion among the non-management directors. During such executive sessions, one director is designated as the "presiding director," who is responsible for leading and facilitating such executive sessions. Currently, the presiding director is Mr. McMahen.

Confidential Telephone Hotline

In accordance with NYSE rules, we have established a toll-free, confidential telephone hotline (the "Hotline") so that interested parties may communicate with the presiding director or with all the non-management directors as a group. All calls to this Hotline are reported to the chairman of the Audit and Conflicts Committee, who is responsible for communicating any necessary information to the other non-management directors. The number of our confidential Hotline is (844) 693-4318.

Section 16(a) Beneficial Ownership Reporting Compliance

Under federal securities laws, directors and executive officers of Enterprise GP and any persons holding more than 10% of our common units are required to report their beneficial ownership of common units and any changes in their beneficial ownership levels to us and the SEC. Specific due dates for these reports have been established by regulation, and we are required to disclose in this annual report any failure to file this information within the specified timeframes. All such reporting was done in a timely manner in 2018.

Table of Contents

ITEM 11. EXECUTIVE COMPENSATION.

Executive Officer Compensation

We do not directly employ any of the persons responsible for managing our business. Instead, we are managed by our general partner, the executive officers of which are employees of EPCO. Our management, administrative and operating functions are primarily performed by employees of EPCO in accordance with the ASA. Pursuant to the ASA, we reimburse EPCO for its compensation costs related to the employment of personnel working on our behalf. For information regarding the ASA, see Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Summary Compensation Table

The following table presents total compensation amounts paid, accrued or otherwise expensed by us with respect to (i) our principal executive officer, (ii) our principal financial officer, (iii) our former principal financial officer and (iv) the three highest paid officers of our general partner, other than our principal executive and financial officers, for the year ended December 31, 2018. Collectively, these individuals were our "named executive officers" for 2018. To the extent such individuals were named executive officers in the prior two years, their total compensation for those years is presented as well.

Name and Principal Position	Year	Cash Salary ($)	Bonus ($)	Equity-Based Awards ($) (1)	All Other Compensation ($) (2)	Total ($)
A. James Teague	2018	$837,500	$2,716,250	$4,359,306	$ 706,531	$8,619,587
CEO,	2017	800,000	2,205,000	4,041,800	651,138	7,697,938
(Principal Executive Officer)	2016	800,000	2,100,000	3,989,926	606,309	7,496,235
W. Randall Fowler	2018	567,188	1,845,000	2,736,631	430,337	5,579,156
President and CFO,	2017	525,000	1,181,250	2,425,080	374,191	4,505,521
(Principal Financial Officer)	2016	521,178	984,375	2,701,298	328,999	4,535,850
Bryan F. Bulawa (3)	2018	234,357	--	1,002,694	4,227,971	5,465,022
former Senior Vice President and CFO,	2017	314,500	267,750	922,685	182,157	1,687,092
(former Principal Financial Officer)	2016	314,500	245,438	1,292,173	143,905	1,996,016
Graham W. Bacon	2018	418,750	411,000	3,159,310	315,136	4,304,196
Executive Vice President,	2017	393,750	315,000	1,674,460	263,501	2,646,711
Operations and Engineering	2016	375,000	294,000	1,958,576	206,541	2,834,117
William Ordemann	2018	460,150	308,500	1,823,080	318,608	2,910,338
Executive Vice President,	2017	451,150	367,500	1,674,460	302,070	2,795,180
Strategy Development and Implementation	2016	451,150	357,000	1,891,366	230,291	2,929,807
Brent B. Secrest	2018	332,500	359,750	2,007,334	168,921	2,868,505
Senior Vice President, Commercial	2017	306,750	262,500	1,154,800	378,084	2,102,134

(1) Amounts represent our estimated share of the aggregate grant date fair value of equity-based awards granted during each year presented.
(2) Amounts include (i) contributions in connection with funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on equity-based awards, (iii) the imputed value of life insurance premiums paid on behalf of the officer, (iv) employee retention payments and (v) other amounts.
(3) Mr. Bulawa served as our CFO, and one of our principal financial officers, until his resignation on August 24, 2018. The amount presented under the column labeled “Other” includes our share of a separation payment, or $4,080,000. The separation payment was based on a number of factors, including, among other things, his tenure at the partnership and the number of equity awards he surrendered upon resignation.

Table of Contents

Bonus amounts shown in the preceding table represent discretionary annual awards earned by each named executive officer with respect to the year presented. For the years ended December 31, 2017 and 2016, the dollar value of each officer's discretionary bonus (less any retirement plan deductions and withholding taxes) was remitted through the issuance of an equivalent value of newly issued Enterprise common units in February of the respective following year. For the year ended December 31, 2018, the dollar value of each officer's bonus (less applicable deductions and taxes) was remitted half in cash and half in newly issued Enterprise common units, with both amounts provided to the employee in February 2019.

The following table presents the components of "All Other Compensation" for each named executive officer for the year ended December 31, 2018:

Named Executive Officer	Contributions Under Funded, Qualified, Defined Contribution Retirement Plans	Quarterly Distributions Paid On Equity-Based Awards	Life Insurance Premiums	Other	Total All Other Compensation
A. James Teague	$ 33,000	$ 659,663	$ 7,663	$ 6,205	$ 706,531
W. Randall Fowler	22,687	398,213	3,267	6,170	430,337
Bryan F. Bulawa (2)	25,712	118,904	561	4,082,794	4,227,971
Graham W. Bacon	33,000	273,588	2,838	5,710	315,136
William Ordemann	33,000	276,433	2,838	6,337	318,608
Brent B. Secrest	30,250	132,731	990	4,950	168,921

(1) Reflects aggregate cash payments made to the named executive officer in connection with (i) distribution equivalent rights ("DERs") issued in tandem with phantom unit awards and (ii) distributions paid in connection with profits interest awards. With respect to DER amounts allocated to us, the following cash payments were made to the named executive officers during the year ended December 31, 2018: Mr. Teague, $639,530; Mr. Fowler, $378,233; Mr. Bulawa, $106,334; Mr. Bacon, $250,579; Mr. Ordemann, $256,300; and Mr. Secrest, $119,628.

(2) Mr. Bulawa served as our CFO, and one of our principal financial officers, until his resignation on August 24, 2018. The amount presented under the column labeled "Other" includes our share of a separation payment, or $4,080,000. The separation payment was based on a number of factors, including, among other things, his tenure at the partnership and the number of equity awards he surrendered upon resignation.

Compensation Discussion and Analysis

Elements of Compensation

With respect to our named executive officers, compensation paid or awarded by us reflects only that portion of compensation paid by EPCO and allocated to us pursuant to the ASA, including an allocation of a portion of the cost of long-term incentive plans of EPCO. The elements of EPCO's compensation program, along with EPCO's other incentives (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The objective of EPCO's compensation program is to provide competitive compensation opportunities that will align and drive employee performance toward the creation of sustained long-term unitholder value. We believe that our compensation program allows us to attract, motivate and retain high quality talent with the skills and competencies we require. Our compensation packages are designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both our partnership and individual levels and to avoid risks that are likely to conflict with our risk management policies.

For the three years ended December 31, 2018, the primary elements of compensation for the named executive officers consisted of annual cash base salary, discretionary annual bonus (satisfied in whole or part through the issuance of Enterprise common units), equity awards under long-term incentive arrangements and other compensation, including very limited perquisites. With respect to the annual periods presented in the Summary Compensation Table, EPCO's compensation package for the named executive officers did not include any compensation elements based on targeted performance-based criteria. We believe that the absence of targeted performance-based criteria has the effect of discouraging excessive risk taking by our named executive officers.

Table of Contents

Changes in the base salaries of our named executive officers during the three years ending December 31, 2018 were largely budget-driven and made consistent relative to increases in the base salaries of our other executive officers.

The bonus awards are discretionary and, in combination with annual base salaries, are intended to yield competitive total compensation levels for the named executive officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the named executive officer may perform services. The annual bonus amount presented for each named executive officer reflects a general consideration of our overall financial results for those periods. This consideration takes into account a number of our financial measures (e.g., non-GAAP gross operating margin and distributable cash flow metrics) and our 5-year equity total return performance relative to peers, without any weight or formula given to any specific financial performance measure. In addition, a subjective judgment of each named executive officer's performance for those periods is taken into account and reflected in the annual bonus amounts. The bonus amounts are also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

Each of our named executive officers has been granted equity-based compensation. The amount of equity-based compensation granted to our named executive officers reflects a general consideration of our overall financial performance, along with a subjective judgment of each named executive officer's contribution in support of that performance, without any weight or formula given to any specific financial performance measure. The values of equity-based awards granted to the named executive officers are also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers. Each of the named executive officers received grants of phantom unit awards for the periods presented in the summary compensation table.

In addition, each of our named executive officers was granted a "profits interest" in one or more of the Employee Partnerships, which serve as long-term incentive arrangements for key employees of EPCO. The names of the Employee Partnerships in which one or more of our named executive officers participate are: EPD PubCo Unit I L.P. ("PubCo I"); EPD PubCo Unit II L.P. ("PubCo II"); EPD PrivCo Unit I L.P. ("PrivCo I"); and EPD 2018 Unit IV L.P. ("EPD IV"). If certain conditions are met, the employee participants in each Employee Partnership will be entitled to (i) a residual profits interest in the assets of the Employee Partnership at liquidation, along with (ii) quarterly cash distributions. For a brief description of the profits interest awards, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

EPCO expects to continue its policy of paying for limited perquisites attributable to our named executive officers. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2018.

Overview of Decision-Making Process regarding Compensation of Named Executive Officers

The Audit and Conflicts Committee of our general partner, with input from the EPCO Trustees and EPCO's human resources department, has ultimate decision-making authority with respect to the compensation of our CEO and our President. The compensation of our other named executive officers (other than any equity-based awards granted under EPCO's long-term incentive plans) is determined by our CEO and our President. Neither EPCO nor our general partner has a separate compensation committee; however, grants of equity-based compensation under EPCO's long-term incentive plans (e.g., phantom unit awards) to our named executive officers, including our CEO and our President, must be approved by the Audit and Conflicts Committee. The issuance of profits interest awards was approved by EPCO's Board of Directors.

The overall compensation of each named executive officer is not based on any formula or specific performance criteria; rather, the Audit and Conflicts Committee, our President, our CEO and EPCO (as applicable) determine an appropriate level and mix of compensation for each officer on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that the Audit and Conflicts Committee or our President and our CEO (as applicable) may take into account in making the case-by-case compensation determinations include the total value of all elements of compensation and the appropriate balance of internal pay equity among our executive officers. The Audit and Conflicts Committee, our President, our CEO and EPCO (as applicable) also consider individual

Table of Contents

performance, levels of responsibility and value to the organization. All compensation determinations are subjective and discretionary.

In making compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by third party compensation consultants. In 2017, EPCO engaged Meridian Compensation Partners, LLC (the "Consultant") to complete a detailed review of executive compensation relative to our industry. In connection with this review, the Consultant provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors. The market data for industry competitors included information from CenterPoint Energy, Inc.; Dominion Energy, Inc.; Enbridge Inc.; ETP; Kinder Morgan Inc.; Magellan Midstream Partners, L.P.; ONEOK, Inc.; Plains All American Pipeline, L.P.; Spectra Energy Corp.; Sunoco Logistics Partners L.P.; Targa Resources Corporation; The Williams Companies, Inc.; and TransCanada Corporation.

Neither we, nor EPCO, which engages the Consultant, are aware of the specific data of the companies included in the Consultant's proprietary database for specific positions. EPCO uses the information provided in the Consultant's analysis to gauge whether compensation levels reported by the Consultant and the general ranges of compensation for EPCO employees in similar positions are comparable, but that comparison is only a factor taken into consideration and may or may not impact compensation of our named executive officers, for which our Audit and Conflicts Committee (in the case of our President's and our CEO's compensation) or our President and our CEO (in the case of compensation to be paid to our other named executive officers) have the ultimate decision-making authority. EPCO does not otherwise engage in benchmarking for the named executive officers' positions.

Allocation of Compensation between Us and EPCO and its other affiliates

Under the ASA, the compensation costs of our named executive officers, including those costs related to equity-based awards, are allocated between us and other affiliates of EPCO based on the estimated amount of time that each officer spends on our consolidated businesses in any fiscal year. These percentages are reassessed at least quarterly. The following table presents the average approximate amount of time devoted by each of our named executive officers to our consolidated businesses and to EPCO and its other privately held affiliates during each of the years indicated.

Named Executive Officer	Year	Enterprise Products Partners	EPCO and its other affiliates	Total Time Allocated
A. James Teague	2018	100%	--	100%
	2017	100%	--	100%
	2016	100%	--	100%
W. Randall Fowler	2018	75%	25%	100%
	2017	75%	25%	100%
	2016	75%	25%	100%
Bryan F. Bulawa	2018	85%	15%	100%
	2017	85%	15%	100%
	2016	85%	15%	100%
William Ordemann	2018	100%	--	100%
	2017	100%	--	100%
	2016	100%	--	100%

Graham W. Bacon	2018	100%	--	100%
	2017	100%	--	100%
	2016	100%	--	100%
Brent B. Secrest	2018	100%	--	100%
	2017	100%	--	100%

127

Table of Contents

Grants of Equity-Based Awards in Fiscal Year 2018

The following table presents information concerning each grant of an equity-based award in 2018 to a named executive officer for which we will be allocated our pro rata share of the related cost under the ASA.

Award Type/Named Executive Officer	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#)	Target (#)	Maximum (#)	Grant Date Fair Value of Equity-Based Awards ($) (1)
Phantom unit awards: (2)					
A. James Teague	2/12/18	--	162,600	--	$4,359,306
W. Randall Fowler	2/12/18	--	136,100	--	2,736,631
Graham W. Bacon	2/12/18	--	68,000	--	1,823,080
William Ordemann	2/12/18	--	68,000	--	1,823,080
Brent B. Secrest	2/12/18	--	35,000	--	938,350
Profits interest awards:					
Graham W. Bacon (3)	12/3/18	--	--	--	$1,603,475
Brent B. Secrest (3)	12/3/18	--	--	--	1,068,984

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the estimated percentage of time each named executive officer spent on our consolidated business activities during 2018. Based on current allocations, we estimate that the compensation expense we record for each named executive officer with respect to these awards will equal these amounts over time.
(2) The grant date fair value presented for the phantom unit awards is based, in part, on the closing price of our common units on February 12, 2018 of $26.81 per unit. For information about assumptions utilized in the valuation of these awards, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report, the applicable disclosures of which are incorporated by reference into this Item 11.
(3) Profits interest awards based on Class B limited partner interests in EPD IV. Mr. Bacon's and Mr. Secrest's share of the profits interest in EPD IV was 5.00% and 4.00%, respectively, at December 31, 2018

Awards granted to Mr. Bulawa in February 2018 were cancelled in connection with his cash separation payment paid in September 2018.

Phantom unit awards
The phantom unit awards noted in the preceding table were granted under the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (the "2008 Plan"). Phantom unit awards allow recipients to acquire our common units (at no cost to the recipient apart from fulfilling service and other conditions) once a defined vesting period expires, subject to customary forfeiture provisions. Phantom unit awards generally vest at a rate of 25% per year beginning one year after the grant date and are non-vested until the required service periods expire. At December 31, 2018, substantially all of our phantom unit awards are expected to result in the issuance of common units upon

vesting; therefore, the applicable awards are accounted for as equity-classified awards.

Each phantom unit award includes a tandem DER, which entitles the holder to nonforfeitable cash payments equal to the product of the number of phantom unit awards outstanding for the participant and the cash distribution per common unit paid to our common unitholders.

The 2008 Plan provides for incentive awards to EPCO's key employees and non-employee directors and consultants who perform management, administrative or operational functions for us or our affiliates. Awards granted under the 2008 Plan may be in the form of phantom units, DERs, restricted common units, unit options, unit appreciation rights and other unit-based awards or substitute awards. For information regarding the number of our common units authorized for issuance under the 2008 Plan, see "Securities Authorized for Issuance Under Equity Compensation Plans" under Part III, Item 13 of this annual report.

Table of Contents

Profits interest awards

In December 2018, EPCO Holdings Inc. (“EPCO Holdings”), a privately held affiliate of EPCO, contributed 6,400,000 Enterprise common units that it owned to EPD IV. In exchange for this contribution, EPCO Holdings was admitted as the Class A limited partner of EPD IV. Also on the applicable contribution date, certain key EPCO employees, including two named executive officers, were issued Class B limited partner interests (i.e., profits interest awards) and admitted as Class B limited partners of EPD IV, all without any capital contribution by such employees. EPCO serves as the general partner of EPD IV. The profits interest awards were not issued under the 2008 Plan.

As the Class A limited partner of EPD IV, EPCO Holdings earns a quarterly preferred return equal to $0.4325 per unit on the 6,400,000 common units it contributed, with any residual cash amount remaining in EPD IV being paid to the Class B limited partners on a quarterly basis as a distribution. Upon liquidation of EPD IV, assets having a then current fair market value equal to the Class A limited partner’s capital base will be distributed to EPCO Holdings. Any remaining assets of EPD IV will be distributed to its Class B limited partners as a residual profits interest, which represents the appreciation in value of EPD IV’s assets since the date of EPCO Holdings’ contribution to it, as described above.

Unless otherwise agreed to by EPCO and a majority in interest of the limited partners of EPD IV, this Employee Partnership will terminate at the earliest to occur of (i) 30 days following its vesting date, (ii) a change of control or (iii) a dissolution of such Employee Partnership. The Class B limited partner interests in EPD IV vest five years from December 3, 2018.

Individually, each Class B limited partner interest is subject to forfeiture if the participating employee’s employment with EPCO is terminated prior to vesting, with customary exceptions for death, disability and certain retirements. The risk of forfeiture will also lapse upon certain change of control events. Forfeited individual Class B limited partner interests are allocated to the remaining Class B limited partners.

Vesting of Equity-Based Awards in 2018

The following table presents the vesting of phantom unit awards to our named executive officers during the year ended December 31, 2018. These amounts are presented on a gross basis and do not reflect any allocation of compensation to affiliates under the ASA.

	Unit Awards	
Named Executive Officer	Number of Units Acquired on Vesting (#) (1)	Value Realized on Vesting ($) (2)
A. James Teague	140,925	$3,711,321
W. Randall Fowler	101,738	2,680,101
Bryan F. Bulawa	34,474	908,167
Graham W. Bacon	46,250	1,218,983
William Ordemann	49,875	1,318,965
Brent B. Secrest	18,875	497,569

(1) Represents the gross number of common units acquired upon vesting of restricted common unit

and phantom unit awards, as applicable, before adjustments for associated tax withholdings.
(2) Amount determined by multiplying the gross number of vested phantom unit awards by the closing price of our common units on the date of vesting.

129

Table of Contents

Equity-Based Awards Outstanding at December 31, 2018

The following information summarizes each named executive officer's long-term incentive awards outstanding at December 31, 2018. These amounts are presented on a gross basis and do not reflect any allocation of compensation to affiliates under the ASA.

		Unit Awards	
Award Type/Named Executive Officer	Vesting Date	Number of Units That Have Not Vested (#) (1)	Market Value of Units That Have Not Vested ($) (2,3)
Phantom unit awards: (4)			
A. James Teague	Various	378,275	$9,301,782
W. Randall Fowler	Various	302,574	7,440,295
Graham W. Bacon	Various	151,500	3,725,385
William Ordemann	Various	153,125	3,765,344
Brent B. Secrest	Various	73,750	1,813,513
Profits interest awards:			
A. James Teague:			
PubCo I (5)	2/22/20	--	$159,521
W. Randall Fowler:			
PrivCo I (6)	2/22/21	--	202,809
Graham W. Bacon:			
PubCo I (5)	2/22/20	--	182,309
EPD IV (8)	12/03/23	--	0
William Ordemann:			
PubCo I (5)	2/22/20	--	159,521
Brent B. Secrest			
PubCo II (7)	2/22/21	--	107,191
EPD IV (8)	12/03/23		0

(1) Represents the total number of phantom unit awards outstanding for each named executive officer.

(2) With respect to amounts presented for phantom unit awards, the market values were derived by multiplying the total number of each award type outstanding for the named executive officer by the closing price of our common units on December 31, 2018 (the last trading day of 2018) of $24.59 per unit.

(3) With respect to amounts presented for the profits interest awards, amount represents the estimated liquidation value to be received by the named executive officer based on the closing price of our common units on December 31, 2018 and the terms of liquidation outlined in the applicable Employee Partnership agreement. There was no residual profits interest for EPD IV due to a decrease in the market value of the

common units it owns since the formation date of such Employee Partnership.
(4) Of the 1,059,224 phantom unit awards presented in the table, the vesting schedule is as follows: 395,837 in 2019; 326,537 in 2020; 219,425 in 2021 and 117,425 in 2022.
(5) With respect to PubCo I, the profit interest share held by Messrs. Teague, Bacon and Ordemann at December 31, 2018 was approximately 4.96%, 5.67% and 4.96%, respectively.
(6) Mr. Fowler's share of the profits interest in PrivCo I was approximately 15.46% at December 31, 2018.
(7) Mr. Secrest's share of the profits interest in PubCo II was approximately 3.21% at December 31, 2018.
(8) Mr. Graham's and Mr. Secrest's share of the profits interests in EPD IV was approximately 5.00% and 4.00%, respectively, at December 31, 2018.

Phantom unit awards

For a brief description of phantom unit awards, see "Grants of Equity-Based Awards in Fiscal Year 2018" within this Item 11.

Profits interest awards

For a brief description of the profits interest awards, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Table of Contents

Potential Payments Upon Termination or Change-in-Control

None of the named executive officers have any employment agreements that call for the payment of termination or severance benefits or provide for any payments in the event of a change in control of our general partner.

The vesting of profits interest awards under the Employee Partnerships is subject to acceleration upon a change of control (as defined below). In addition, vesting of equity-based awards under EPCO's long-term incentive plans is subject to acceleration upon a qualifying termination, including termination after a change of control of our general partner. Qualifying termination under such awards generally means a termination as an employee of EPCO or an affiliated group member (i) upon death, (ii) a qualifying long-term disability, (iii) a qualifying retirement, or (iv) within one year after a change of control (as defined), other than a termination for cause (as defined) or termination by such person that is not a qualifying termination for good reason (as defined).

A "change of control" under these awards is generally defined to mean that the descendants, heirs and/or legatees of Dan L Duncan, and/or trusts (including, without limitation, one or more voting trusts) established for their benefit, collectively, cease, directly or indirectly, to control our general partner. Mr. Duncan passed away in March 2010.

Compensation Committee Report

We do not have a separate compensation committee. In addition, we do not directly employ or compensate our named executive officers. Rather, under the ASA, we reimburse EPCO for the compensation of our executive officers. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO and Enterprise GP's CEO, President and Audit and Conflicts Committee.

In light of the foregoing, the Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth above and determined that it be included in this annual report for the year ended December 31, 2018.

Submitted by: Randa Duncan Williams
Richard H. Bachmann
A. James Teague
W. Randall Fowler
Carin M. Barth
Murray E. Brasseux
James T. Hackett
Charles E. McMahen
William C. Montgomery
John R. Rutherford
Richard S. Snell
Harry P. Weitzel

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Securities Exchange Act, as amended, that incorporate future filings, including this annual report, in whole or in part, the foregoing Compensation Committee Report shall not be incorporated by reference into any such filings.

Table of Contents

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of Enterprise GP served as members of the compensation committee of another entity that has or had an executive officer who served as a member of our Board during the year ended December 31, 2018. As previously noted, we do not have a separate compensation committee. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers with respect to 2018 were made, as applicable, by EPCO and Enterprise GP's CEO, President and Audit and Conflicts Committee.

Pay Ratio Disclosure

Pursuant to a mandate of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the SEC requires annual disclosure of the ratio of (i) the median of the total annual compensation of all employees of a registrant to (ii) the total annual compensation of the registrant's principal executive officer. Our principal executive officer is Mr. Teague (who serves as CEO of our general partner). The following table summarizes the information used to derive the required pay ratio for the year ended December 31, 2018:

Median total annual compensation	$134,951
Total annual compensation of Mr. Teague (CEO)	$8,619,587
Ratio of CEO compensation to median compensation	64 : 1

The median total annual compensation was determined as follows:

§ First, a list was prepared of all active EPCO employees, excluding Mr. Teague and those on long-term disability, that devote all or a substantial portion of their time to our consolidated businesses and affairs. This list was based on employee information as of December 31, 2018. There are approximately 7,000 EPCO personnel who spend all or a substantial portion of their time engaged in our business.

§ Second, basic wage data for each employee was extracted from Form W-2 information provided to the Internal Revenue Service for calendar year 2018. This information was then sorted and the employees who earned closest to the median compensation (the "median employees") were selected from the list.

§ Third, once the median employees were selected, their respective total annual compensation for 2018 was determined using the same method used to determine Mr. Teague's total annual compensation for 2018 as presented in the Summary Compensation Table within this Part III, Item 11. The total annual compensation for each median employee was then averaged to derive our median total annual compensation amount.

Table of Contents

Director Compensation

Neither we nor our general partner provide additional compensation to employees of EPCO for their services as directors of Enterprise GP. For calendar year 2018, the independent voting directors of our general partner were compensated as follows:

§ each received an $85,000 annual cash retainer and an annual grant of our common units having a fair market value, based on the closing price of such security on the trading day immediately preceding the date of grant, of $85,000;

§ if the individual served as a chairman of the Audit and Conflicts Committee, then he received an additional $20,000 annual cash retainer;

§ if the individual served as a chairman of the Governance Committee, then he received an additional $15,000 annual cash retainer; and,

§ for those independent voting directors that serve on the Capital Projects Committee, a $2,500 per meeting cash fee for attendance at meetings of this committee.

Our advisory directors, Messrs. Casey and Smith, each received a $150,000 annual cash retainer in 2018. As an honorary director, O.S. Andras received a $20,000 annual cash retainer.

The director compensation program for calendar year 2019 is expected to be the same as 2018.

We bear all costs attributable to the compensation of directors of our general partner. The following table summarizes compensation paid to the non-employee directors of our general partner in 2018:

Non-Employee Director	Fees Earned or Paid in Cash ($)	Value of Equity-Based Awards ($)	Total ($)
Carin M. Barth	$85,000	$ 85,000	$170,000
Larry J. Casey (1)	150,000	--	150,000
James T. Hackett (2)	100,000	85,000	185,000
Charles E. McMahen (3)	105,000	85,000	190,000
William C. Montgomery	85,000	85,000	170,000
Edwin E. Smith (1)	150,000	--	150,000
Richard S. Snell	85,000	85,000	170,000
O.S. Andras (4)	20,000	--	20,000

(1) Messrs. Casey and Smith serve as advisory directors.
(2) Mr. Hackett serves as chairman of the Governance Committee.
(3) Mr. McMahen serves as chairman of the Audit and Conflicts Committee.
(4) Mr. Andras serves as an honorary director.

133

Table of Contents

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS.

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of February 15, 2019, regarding each person known by Enterprise GP to beneficially own more than 5% of our limited partner units:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Randa Duncan Williams (1) 1100 Louisiana Street, 10th Floor Houston, Texas 77002	697,780,395	31.9%

(1) For a detailed listing of the ownership amounts that comprise Ms. Duncan Williams' total beneficial ownership of our common units, see the table presented in the following section, "Security Ownership of Management," within this Part III, Item 12.

As noted previously, Ms. Duncan Williams is a DD LLC Trustee and an EPCO Trustee. Ms. Duncan Williams is also currently Chairman and a director of EPCO and Chairman of the Board and a director of Enterprise GP. Ms. Duncan Williams disclaims beneficial ownership of the limited partner units beneficially owned by the EPCO Trustees and the DD LLC Trustees, except to the extent of her voting and dispositive interests in such units.

Security Ownership of Management

The following tables set forth certain information regarding the beneficial ownership of our common units, as of February 15, 2019 by (i) our named executive officers for 2018; (ii) the current directors of Enterprise GP; and (iii) the current directors and executive officers (including named executive officers) of Enterprise GP as a group. All beneficial ownership information has been furnished by the respective directors and executive officers. Each person has sole voting and dispositive power over the securities shown unless indicated otherwise.

	Positions with Enterprise GP at February 15, 2019	Amount and Nature Of Beneficial Ownership	Percent of Class
Randa Duncan Williams:	Director and Chairman of the Board		
Units controlled by EPCO Voting Trust:			
Through EPCO		66,408,549	3.0%
Through EPCO Investments L.P.		8,346,154	*
Through EPCO Holdings, Inc.		590,944,499	27.0%
Through Employee Partnerships		14,773,688	*
Units controlled by Alkek and Williams, Ltd.		389,021	*
Units controlled by Chaswil, Ltd.		10,000	*
Units controlled by family trusts (1)		16,895,354	*
Units owned personally (2)		13,130	*
Total for Randa Duncan Williams		697,780,395	31.9%

* Represents a beneficial ownership of less than 1% of class
(1) The number of common units presented for Ms. Duncan Williams includes common units held by family trusts for which she serves as a director of an entity trustee but has disclaimed beneficial ownership (except to the extent of her pecuniary interest therein).
(2) The number of common units presented for Ms. Duncan Williams includes 9,090 common units held by her spouse and 4,040 common units held jointly with her spouse.

Table of Contents

EPCO and its privately held affiliates have pledged 108,222,618 of our common units that they own as security under their credit facilities. These credit facilities include customary provisions regarding potential events of default. As a result, a change in ownership of these units could result if an event of default ultimately occurred.

	Positions with Enterprise GP at February 15, 2019	Amount and Nature Of Beneficial Ownership	Percent of Class
Richard H. Bachmann (1)	Director and Vice Chairman of the Board	1,530,926	*
A. James Teague (2,3)	Director and CEO	1,916,429	*
W. Randall Fowler (2,4)	Director and President and CFO	1,550,760	*
Carin M. Barth	Director	44,420	*
Murray E. Brasseux (5)	Director	15,767	*
James T. Hackett (6)	Director	272,578	*
Charles E. McMahen	Director	110,974	*
William C. Montgomery	Director	49,920	*
John R. Rutherford	Director	21,085	*
Richard S. Snell (7)	Director	69,286	*
Harry P. Weitzel (8)	Director and Senior Vice President, General Counsel and Secretary	71,035	*
William Ordemann (2,9)	Executive Vice President	1,018,321	*
Graham W. Bacon (2,10)	Executive Vice President	261,363	*
Brent B. Secrest (2,11)	Senior Vice President	77,397	*
Bryan F. Bulawa (2,12)	Former Senior Vice President and CFO	163,787	*
All directors and executive officers (including all named executive officers) of Enterprise GP, as a group (18 individuals in total) (13)		705,134,366	32.2%

* Represents a beneficial ownership of less than 1% of class
(1) The number of common units presented for Mr. Bachmann includes 9,588 common units held by his spouse. In addition, the number of common units presented for Mr. Bachmann includes an aggregate 150,000 phantom units that vested in late February 2019, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(2) These individuals are named executive officers for the year ended December 31, 2018.
(3) The number of common units presented for Mr. Teague includes (i) 56,390 common units held by a trust and (ii) 37,175 common units held by his spouse. In addition, the number of common units presented for Mr. Teague includes an aggregate 146,075 phantom units that vested in late February 2019, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(4) The number of common units presented for Mr. Fowler includes 510,000 common units held by a family limited partnership (for which he has disclaimed beneficial ownership except to the extent of his pecuniary interest). In addition, the number of common units presented for Mr. Fowler includes an aggregate 113,262 phantom units that

vested in late February 2019, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

(5) The number of common units presented for Mr. Brasseux includes 2,882 common units held by his spouse.

(6) The number of common units presented for Mr. Hackett includes (i) 9,661 common units held by family trusts and (ii) 33,000 common units held by a family limited partnership.

(7) The number of common units presented for Mr. Snell includes 2,956 common units held by his spouse.

(8) The number of common units presented for Mr. Weitzel includes an aggregate 23,400 phantom units that vested in late February 2019, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

(9) The number of common units presented for Mr. Ordemann includes an aggregate 55,250 phantom units that vested in late February 2019, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

(10) The number of common units presented for Mr. Bacon includes an aggregate 55,250 phantom units that vested in late February 2019, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

(11) The number of common units presented for Mr. Secrest includes an aggregate 24,375 phantom units that vested in late February 2019, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

(12) The ownership information presented is based on Mr. Bulawa's reported holdings of our common units immediately prior to his resignation. Mr. Bulawa resigned effective August 24, 2018.

(13) Cumulatively, this group's beneficial ownership amount includes an aggregate 601,916 phantom units that vested in late February 2019, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

Table of Contents

Equity Ownership Guidelines

In order to further align the interests and actions of our general partner's directors and executive officers with our long-term interests and those of our general partner and other unitholders, the Board has adopted and approved certain equity ownership guidelines for our general partner's directors and executive officers. Under these guidelines:

§ each non-management director of our general partner is required to own Enterprise common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such non-management director's aggregate annual cash retainer for service on the Board for the most recently completed calendar year; and

§ each executive officer of our general partner is required to own Enterprise common units having an aggregate value (as defined in the guidelines) of three times the dollar amount of such executive officer's aggregate annual base salary for the most recently completed calendar year.

Securities Authorized for Issuance Under Equity Compensation Plans

Currently, the 2008 Plan is EPCO's only long-term incentive plan under which our common units have been authorized for issuance. The 2008 Plan provides for awards of our common units and other rights to our non-management directors and to consultants and employees of EPCO and its affiliates providing services to us. Awards under the 2008 Plan may be granted in the form of unit options, restricted common units, phantom units, UARs, DERs, unit awards and other unit-based awards or substitute awards. The following table sets forth certain information regarding the 2008 Plan as of January 1, 2019.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Common Unit Options (a)	Weighted-Average Exercise Price of Outstanding Common Unit Options (b)	Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by unitholders: 2008 Plan (1)	--		24,116,132
Equity compensation plans not			

approved by unitholders:		
None	--	--
Total for equity compensation plans	--	24,116,132

(1) At December 31, 2018, the total number of common units authorized for issuance under the 2008 Plan was 45,000,000 common units. This amount increased by 5,000,000 common units on January 1, 2019 and will increase by an additional 5,000,000 common units subsequently on each January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate amount available for issuance under the 2008 Plan exceed 70,000,000 common units.

Table of Contents

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS,
AND DIRECTOR INDEPENDENCE.

Certain Relationships and Related Transactions

We believe that the terms and provisions of our related party agreements are fair to us; however, such agreements and transactions may not be as favorable to us as we could have obtained from unaffiliated third parties.

Additional information regarding our related party transactions is set forth in Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report and is incorporated by reference into this Part III, Item 13.

Review and Approval of Transactions with Related Parties

We consider transactions between us and our subsidiaries and unconsolidated affiliates, on the one hand, and our executive officers and directors (or their immediate family members), our general partner or its affiliates (including other companies owned or controlled by the DD LLC Trustees or the EPCO Trustees), on the other hand, to be related party transactions. As further described below, our partnership agreement sets forth general procedures by which related party transactions and conflicts of interest may be approved or resolved by Enterprise GP or its Audit and Conflicts Committee. In addition, the Audit and Conflicts Committee charter, Enterprise GP's written internal review and approval policies and procedures (referred to as its "management authorization policy") and the amended and restated ASA with EPCO address specific types of related party transactions, as further described below.

Our Audit and Conflicts Committee is comprised of five independent directors: Messrs. Brasseux, McMahen, Montgomery, Rutherford and Snell. In accordance with its charter, the Audit and Conflicts Committee reviews and approves related party transactions:

§ pursuant to our partnership agreement or the limited liability company agreement of Enterprise GP, as such agreements may be amended from time to time;

§ in which an officer or director of Enterprise GP or any of our subsidiaries, or an immediate family member of such an officer or director, has a material financial interest or is otherwise a party;

§ when requested to do so by management or the Board;

§ with a value of $5 million or more (unless such transaction is equivalent to an arm's length or third party transaction); or

§ that it may otherwise deem appropriate from time to time.

The Audit and Conflicts Committee did not review or approve any related party transactions during the year ended December 31, 2018.

Enterprise GP's management authorization policy generally requires Board approval for asset purchase or sales transactions and capital expenditures to the extent such transactions have a value in excess of $250 million. Any such transaction would typically also require Audit and Conflicts Committee review under its charter if such transaction is also a related party transaction.

As noted previously, all of our management, administrative and operating functions are performed by employees of EPCO (pursuant to an administrative services agreement, or ASA) or by other service providers. The ASA governs numerous day-to-day transactions between us, Enterprise GP and EPCO and its affiliates, including the provision by EPCO of administrative and other services to us and our reimbursement to EPCO of costs, without markup or discount, for those services. The ASA was reviewed, approved and recommended to the Board by our Audit and Conflicts Committee, and the Board also approved it upon receiving such recommendation.

Table of Contents

Related party transactions that are outside the scope of the ASA and not reviewed by the Audit and Conflicts Committee are subject to Enterprise GP's management authorization policy. This policy, which applies to related party transactions as well as transactions with third parties, specifies thresholds for our general partner's officers and Board to authorize various categories of transactions, including purchases and sales of assets, commercial and financial transactions and legal agreements.

Partnership Agreement Standards for Audit and Conflicts Committee Review

Under our partnership agreement, whenever a potential conflict of interest exists or arises between Enterprise GP or any of its affiliates, on the one hand, and us, any of our subsidiaries or any partner, on the other hand, any resolution or course of action by Enterprise GP or its affiliates in respect of such conflict of interest is permitted and deemed approved by our limited partners, and will not constitute a breach of our partnership agreement or any agreement contemplated by such agreement, or of any duty stated or implied by law or equity, if the resolution or course of action is or, by operation of the partnership agreement is deemed to be, fair and reasonable to us; provided that, any conflict of interest and any resolution of such conflict of interest will be conclusively deemed fair and reasonable to us if such conflict of interest or resolution is (i) approved by a majority of the members of the Audit and Conflicts Committee (i.e., a "Special Approval" is granted) or (ii) on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from third parties.

The Audit and Conflicts Committee (in connection with its Special Approval process) may consider the following when resolving conflicts of interest:

§ the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

§ the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us);

§ any customary or accepted industry practices and any customary or historical dealings with a particular party;

§ any applicable generally accepted accounting or engineering practices or principles;

§ the relative cost of capital of the parties involved and the consequent rates of return to the equity holders of such parties; and

§ such additional factors as the Audit and Conflicts Committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

The level of review and work performed by the Audit and Conflicts Committee with respect to a given transaction varies depending upon the nature of the transaction and the scope of the Audit and Conflicts Committee's obligation. Examples of functions the Audit and Conflicts Committee may, as it deems appropriate, perform in the course of reviewing a transaction include, but are not limited to:

§ assessing the business rationale for the transaction;

§ reviewing the terms and conditions of the proposed transaction, including consideration and financing requirements, if any;

§

assessing the effect of the transaction on our results of operations, financial condition, cash available for distribution, properties or prospects;

§ conducting due diligence, including interviews and discussions with management and other representatives and reviewing transaction materials and findings of management and other representatives;

§ considering the relative advantages and disadvantages of the transactions to the parties involved;

Table of Contents

§ engaging third party financial advisors to provide financial advice and assistance, including fairness opinions if requested;

§ engaging legal advisors; and

§ evaluating and negotiating the transaction and recommending for approval or approving the transaction, as the case may be.

Nothing contained in our partnership agreement requires the Audit and Conflicts Committee to consider the interests of any party other than us. In the absence of the Audit and Conflicts Committee or our general partner acting in bad faith, the resolution, action or terms so made, taken or provided (including granting Special Approval) by the Audit and Conflicts Committee or our general partner with respect to such matter are deemed conclusive and binding on all persons (including all of our limited partners) and do not constitute a breach of partnership agreement, or any other agreement contemplated thereby, or a breach of any standard of care or duty imposed in our partnership agreement or under the Delaware Revised Uniform Limited Partnership Act or any other law, rule or regulation. Our partnership agreement provides that it is presumed that the resolution, action or terms made, taken or provided by the Audit and Conflicts Committee or our general partner were not made, taken or provided in bad faith, and in any proceeding brought by any limited partner or by or on behalf of such limited partner or any other limited partner or us challenging such resolution, action or terms, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Director Independence

Each of the current members of the Audit and Conflicts Committee, namely Messrs. Brasseux, McMahen, Montgomery, Rutherford and Snell, and two members of the Governance Committee, namely Ms. Barth and Mr. Hackett, have been determined to be independent under the applicable NYSE listing standards and rules of the SEC. For a discussion of independence standards applicable to our Board and factors considered by our Board in making its independence determinations, please refer to "Partnership Governance" included under Part III, Item 10 of this annual report.

Other Matters

An immediate family member of Mr. Teague and two immediate family members of Mr. Ordemann are employees of EPCO who perform services on our behalf. None of these individuals serves as an executive officer of Enterprise GP, EPCO or any of their respective affiliates, and each such individual's compensation and other terms of employment are determined on a basis consistent with EPCO's human resources policies. For 2018, (i) the immediate family member of Mr. Teague earned total compensation from EPCO of $550 thousand and (ii) the two immediate family members of Mr. Ordemann earned total compensation from EPCO of $180 thousand and $175 thousand, respectively.

During 2018, an immediate family member of Ms. Duncan Williams was an employee of EPCO who performed services on our behalf. This individual did not serve as an executive officer of Enterprise GP, EPCO or any of their respective affiliates, and such individual's compensation and other terms of employment were determined on a basis consistent with EPCO's human resources policies. For 2018, this individual earned total compensation from EPCO of $140 thousand.

Mr. Brasseux owns a minority equity interest in Worldwide Power Products, LLC ("Worldwide"), a privately-owned company in the business of buying, selling, renting and servicing generators and buying and selling generator parts. Mr. Brasseux's son-in-law is the Chief Executive Officer and majority equity owner of Worldwide. From time to time, we engage in business transactions with Worldwide. Although the aggregate dollar amount involved in these transactions has not exceeded $120,000 historically, the annual aggregate dollar amount involved in such transactions may exceed $120,000 in the future. The terms of these transactions are determined on an arms-length basis, and Mr. Brasseux (who does not serve as an employee or director of Worldwide) does not participate in the negotiation or approval of any such transactions.

Table of Contents

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

With the approval of the Audit and Conflicts Committee of our general partner, we have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, "Deloitte & Touche") as our independent registered public accounting firm and principal accountants. The following table summarizes amounts billed to us by Deloitte & Touche for each of the years presented, as applicable:

	For the Year Ended December 31,	
	2018	2017
Audit fees (1)	$5,253,365	$5,047,700

(1) Audit fees for 2018 and 2017 include $50,000 and $135,000, respectively, of charges for audit-related projects that were reimbursed by business partners.

As presented in the preceding table, "Audit Fees" represent amounts billed for each year in connection with (i) the annual audit of our consolidated financial statements filed on Form 10-K and related internal controls over financial reporting, (ii) the quarterly review of our consolidated financial statements filed on Form 10-Q, (iii) standalone annual audits of our consolidated subsidiaries and (iv) those services normally provided by Deloitte & Touche in connection with our statutory and regulatory filings or engagements, including comfort letters, consents and other services related to SEC matters. We did not engage Deloitte & Touche to perform any other services for us during the last two years. We are prohibited from using Deloitte & Touche to perform general bookkeeping, human resources or management functions for us, and any other service not permitted by the PCAOB.

In connection with its oversight responsibilities, the Audit and Conflicts Committee has adopted a pre-approval policy regarding any services to be performed by Deloitte & Touche. The pre-approval policy includes four primary service categories: Audit, Audit-related, Tax and Other. When Deloitte & Touche's services are required, management and Deloitte & Touche discuss the proposed work with the Audit and Conflicts Committee. These discussions typically address the reasons for the project, the scope of the work to be performed and an estimate of the fee to be charged by Deloitte & Touche for such work. The Audit and Conflicts Committee discusses the request with management and Deloitte & Touche and, if the work is deemed necessary and appropriate for Deloitte & Touche to perform, approves the request subject to the fee estimate presented (the initial "pre-approved" fee amount). If at a later date, it appears that the initial pre-approved fee amount is insufficient to complete the work, management and Deloitte & Touche must present a supplemental request to the Audit and Conflicts Committee to increase the approved amount along with reasons for the increase. Under the pre-approval policy, management cannot act upon its own to authorize an expenditure for Deloitte & Touche services outside of the pre-approved amounts. On a quarterly basis, the Audit and Conflicts Committee is provided a schedule that compares the pre-approved amounts for each primary service category with the actual fees billed for each type of service. We believe the Audit and Conflicts Committee's pre-approval process helps to ensure the independence of Deloitte & Touche from management.

Table of Contents

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as a part of this annual report:

(1) Financial Statements: See "Index to Consolidated Financial Statements" beginning on page F-1 of this annual report for the financial statements included herein.

(2) Financial Statement Schedules: The separate filing of financial statement schedules has been omitted because such schedules are either not applicable or the information called for therein appears in the footnotes of our Consolidated Financial Statements.

(3) Exhibits:

Exhibit Number	Exhibit*
2.1	Merger Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed December 15, 2003).
2.2	Amendment No. 1 to Merger Agreement, dated as of August 31, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products Management LLC, GulfTerra Energy Partners, L.P. and GulfTerra Energy Company, L.L.C. (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2004).
2.3	Parent Company Agreement, dated as of December 15, 2003, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.2 to Form 8-K filed December 15, 2003).
2.4	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 21, 2004).
2.5	Purchase and Sale Agreement (Gas Plants), dated as of December 15, 2003, by and between El Paso Corporation, El Paso Field Services Management, Inc., El Paso Transmission, L.L.C., El Paso Field Services Holding Company and Enterprise Products Operating L.P. (incorporated by reference to Exhibit 2.4 to Form 8-K filed December 15, 2003).
2.6	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub B LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed June 29, 2009).
2.7	Agreement and Plan of Merger, dated as of June 28, 2009, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Sub A LLC, TEPPCO Partners, L.P. and Texas Eastern Products Pipeline Company, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 29, 2009).
2.8	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise ETE LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed September 7, 2010).
2.9	Agreement and Plan of Merger, dated as of September 3, 2010, by and among Enterprise Products GP, LLC, Enterprise GP Holdings L.P. and EPE Holdings, LLC (incorporated by reference to Exhibit 2.2 to Form 8-K filed September 7, 2010).

141

Table of Contents

2.10	Contribution Agreement, dated as of September 30, 2010, by and between Enterprise Products Company and Enterprise Products Partners L.P. (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2010).
2.11	Agreement and Plan of Merger, dated as of April 28, 2011, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPD MergerCo LLC, Duncan Energy Partners L.P. and DEP Holdings, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed April 29, 2011).
2.12	Contribution and Purchase Agreement, dated as of October 1, 2014, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc. and OTB Holdco, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed October 1, 2014).
2.13	Agreement and Plan of Merger, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Holdings LLC, EPOT MergerCo LLC, Oiltanking Partners, L.P. and OTLP GP, LLC (incorporated by reference to Exhibit 2.1 to Form 8-K filed November 12, 2014).
2.14	Amendment No. 1 dated as of June 6, 2018 to Contribution and Purchase Agreement, by and among Enterprise Products Partners L.P., Oiltanking Holding Americas, Inc., Enterprise Products Holdings LLC and Marquard & Bahls, AG (incorporated by reference to Exhibit 2.2 to Form 8-K filed June 12, 2018).
3.1	Certificate of Limited Partnership of Enterprise Products Partners L.P. (incorporated by reference to Exhibit 3.6 to Form 10-Q filed November 9, 2007).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Enterprise Products Partners L.P., filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.6 to Form 8-K filed November 23, 2010).
3.3	Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated November 22, 2010 (incorporated by reference to Exhibit 3.2 to Form 8-K filed November 23, 2010).
3.4	Amendment No. 1 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 11, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 16, 2011).
3.5	Amendment No. 2 to Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated effective as of August 21, 2014 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 26, 2014).
3.6	Amendment No. 3 to the Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated as of November 28, 2017 (incorporated by reference to Exhibit 3.1 to Form 8-K filed December 1, 2017).
3.7#	Amendment No. 4 to the Sixth Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P., dated as of February 26, 2019.
3.8	Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC) (incorporated by reference to Exhibit 3.3 to Form S-1/A Registration Statement, Reg. No. 333-124320, filed by Enterprise GP Holdings L.P. on July 22, 2005).
3.9	Certificate of Amendment to Certificate of Formation of Enterprise Products Holdings LLC (formerly named EPE Holdings, LLC), filed on November 22, 2010 with the Delaware Secretary of State (incorporated by reference to Exhibit 3.5 to Form 8-K filed November 23, 2010).
3.10	Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC dated effective as of September 7, 2011 (incorporated by reference to Exhibit 3.1 to Form 8-K filed September 8, 2011).
3.11	Amendment No. 1 to Fifth Amended and Restated Limited Liability Company Agreement of Enterprise Products Holdings LLC, dated effective as of April 26, 2017 (incorporated by reference to Exhibit 3.1 to Form 8-K filed May 2, 2017).
3.12	Company Agreement of Enterprise Products Operating LLC dated June 30, 2007 (incorporated by reference to Exhibit 3.3 to Form 10-Q filed August 8, 2007).
3.13	Certificate of Incorporation of Enterprise Products OLPGP, Inc., dated December 3, 2003 (incorporated by reference to Exhibit 3.5 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).
3.14	

Bylaws of Enterprise Products OLPGP, Inc., dated December 8, 2003 (incorporated by reference to Exhibit 3.6 to Form S-4 Registration Statement, Reg. No. 333-121665, filed December 27, 2004).

Table of Contents

4.1	Form of Common Unit certificate (incorporated by reference to Exhibit A to Exhibit 3.1 to Form 8-K filed August 16, 2011).
4.2	Indenture, dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 14, 2000).
4.3	Second Supplemental Indenture, dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.4	Third Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and U.S. Bank National Association, as successor Trustee (incorporated by reference to Exhibit 4.55 to Form 10-Q filed August 8, 2007).
4.5	Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 6, 2004).
4.6	Fourth Supplemental Indenture, dated as of October 4, 2004, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.5 to Form 8-K filed October 6, 2004).
4.7	Sixth Supplemental Indenture, dated as of March 2, 2005, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 3, 2005).
4.8	Amended and Restated Eighth Supplemental Indenture, dated as of August 25, 2006, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed August 25, 2006).
4.9	Ninth Supplemental Indenture, dated as of May 24, 2007, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed May 24, 2007).
4.10	Tenth Supplemental Indenture, dated as of June 30, 2007, among Enterprise Products Operating L.P., as Original Issuer, Enterprise Products Partners L.P., as Parent Guarantor, Enterprise Products Operating LLC, as New Issuer, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.54 to Form 10-Q filed August 8, 2007).
4.11	Thirteenth Supplemental Indenture, dated as of April 3, 2008, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.12	Sixteenth Supplemental Indenture, dated as of October 5, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.13	Seventeenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.14	Eighteenth Supplemental Indenture, dated as of October 27, 2009, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.15	Nineteenth Supplemental Indenture, dated as of May 20, 2010, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 20, 2010).

Table of Contents

4.16	Twentieth Supplemental Indenture, dated as of January 13, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.17	Twenty-First Supplemental Indenture, dated as of August 24, 2011, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.18	Twenty-Second Supplemental Indenture, dated as of February 15, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.19	Twenty-Third Supplemental Indenture, dated as of August 13, 2012, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.20	Twenty-Fourth Supplemental Indenture, dated as of March 18, 2013, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.21	Twenty-Fifth Supplemental Indenture, dated as of February 12, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.22	Twenty-Sixth Supplemental Indenture, dated as of October 14, 2014, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.23	Twenty-Seventh Supplemental Indenture, dated as of May 7, 2015, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Parent Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.24	Twenty-Eighth Supplemental Indenture, dated as of April 13, 2016, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.25	Twenty-Ninth Supplemental Indenture, dated as of August 16, 2017, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.26	Thirtieth Supplemental Indenture, dated as of February 15, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.27	Thirty-First Supplemental Indenture, dated as of February 15, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 15, 2018).
4.28	Thirty-Second Supplemental Indenture, dated as of October 11, 2018, among Enterprise Products Operating LLC, as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wells Fargo Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 8-K filed October 11, 2018).

Table of Contents

4.29	Form of Global Note representing $499.2 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.30	Form of Global Note representing $350.0 million principal amount of 6.65% Series B Senior Notes due 2034 with attached Guarantee (incorporated by reference to Exhibit 4.19 to Form S-3 Registration Statement, Reg. No. 333-123150, filed March 4, 2005).
4.31	Form of Global Note representing $250.0 million principal amount of 5.75% Series B Senior Notes due 2035 with attached Guarantee (incorporated by reference to Exhibit 4.32 to Form 10-Q filed November 4, 2005).
4.32	Form of Global Note representing an aggregate of $550.0 million principal amount of Junior Subordinated Notes due 2066 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.2 to Form 8-K filed August 25, 2006).
4.33	Form of Global Note representing $700.0 million principal amount of 6.50% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed April 3, 2008).
4.34	Form of Global Note representing $500.0 million principal amount of 5.25% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.35	Form of Global Note representing $600.0 million principal amount of 6.125% Senior Notes due 2039 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed October 5, 2009).
4.36	Form of Global Note representing $349.7 million principal amount of 6.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit D to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.37	Form of Global Note representing $399.6 million principal amount of 7.55% Senior Notes due 2038 with attached Guarantee (incorporated by reference to Exhibit E to Exhibit 4.1 to Form 8-K filed October 28, 2009).
4.38	Form of Global Note representing $285.8 million principal amount of Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.2 to Form 8-K filed October 28, 2009).
4.39	Form of Global Note representing $1.0 billion principal amount of 5.20% Senior Notes due 2020 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.40	Form of Global Note representing $600.0 million principal amount of 6.45% Senior Notes due 2040 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 20, 2010).
4.41	Form of Global Note representing $750.0 million principal amount of 5.95% Senior Notes due 2041 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed January 13, 2011).
4.42	Form of Global Note representing $650.0 million principal amount of 4.05% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.43	Form of Global Note representing $600.0 million principal amount of 5.70% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 24, 2011).
4.44	Form of Global Note representing $750.0 million principal amount of 4.85% Senior Notes due 2042 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.25 to Form 10-Q filed May 10, 2012).
4.45	Form of Global Note representing $1.1 billion principal amount of 4.45% Senior Notes due 2043 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 13, 2012).
4.46	Form of Global Note representing $1.25 billion principal amount of 3.35% Senior Notes due 2023 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed March 18, 2013).

Table of Contents

4.47	Form of Global Note representing $1.0 billion principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.48	Form of Global Note representing $850.0 million principal amount of 3.90% Senior Notes due 2024 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.49	Form of Global Note representing $1.15 billion principal amount of 5.10% Senior Notes due 2045 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed February 12, 2014).
4.50	Form of Global Note representing $800.0 million principal amount of 2.55% Senior Notes due 2019 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.51	Form of Global Note representing $1.15 billion principal amount of 3.75% Senior Notes due 2025 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.52	Form of Global Note representing $400.0 million principal amount of 4.95% Senior Notes due 2054 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.4 to Form 8-K filed October 14, 2014).
4.53	Form of Global Note representing $400.0 million principal amount of 4.85% Senior Notes due 2044 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed March 18, 2013).
4.54	Form of Global Note representing $750.0 million principal amount of 1.65% Senior Notes due 2018 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.55	Form of Global Note representing $875.0 million principal amount of 3.70% Senior Notes due 2026 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.56	Form of Global Note representing $875.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.57	Form of Global Note representing $575.0 million principal amount of 2.85% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.58	Form of Global Note representing $575.0 million principal amount of 3.95% Senior Notes due 2027 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed April 13, 2016).
4.59	Form of Global Note representing $100.0 million principal amount of 4.90% Senior Notes due 2046 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed May 7, 2015).
4.60	Form of Global Note representing $700 million principal amount of Junior Subordinated Notes D due 2077 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.61	Form of Global Note representing $1.0 billion principal amount of Junior Subordinated Notes E due 2077 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed August 16, 2017).
4.62	Form of Global Note representing $750.0 million principal amount of 2.80% Senior Notes due 2021 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.63	Form of Global Note representing $1.25 billion principal amount of 4.25% Senior Notes due 2048 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.4 to Form 8-K filed February 15, 2018).
4.64	Form of Global Note representing $700 million principal amount of Junior Subordinated Notes F due 2078 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed February 15, 2018).

4.65	Form of Global Note representing $750.0 million principal amount of 3.50% Senior Notes due 2022 with attached Guarantee (incorporated by reference to Exhibit A to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.66	Form of Global Note representing $1,000.0 million principal amount of 4.15% Senior Notes due 2028 with attached Guarantee (incorporated by reference to Exhibit B to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.67	Form of Global Note representing $1,250.0 million principal amount of 4.80% Senior Notes due 2049 with attached Guarantee (incorporated by reference to Exhibit C to Exhibit 4.3 to Form 8-K filed October 11, 2018).
4.68	Replacement Capital Covenant, dated July 18, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed July 19, 2006).
4.69	First Amendment to Replacement Capital Covenant dated August 25, 2006, executed by Enterprise Products Operating L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.2 to Form 8-K filed August 25, 2006).
4.70	Replacement Capital Covenant, dated May 24, 2007, executed by Enterprise Products Operating L.P. and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 99.1 to Form 8-K filed May 24, 2007).
4.71	Replacement Capital Covenant, dated October 27, 2009, executed by Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.9 to Form 8-K filed October 28, 2009).
4.72	Amendment to Replacement Capital Covenants, dated May 6, 2015, executed by Enterprise Products Operating LLC and Enterprise Products Partners L.P. in favor of the covered debtholders described therein (incorporated by reference to Exhibit 4.59 to Form 10-Q filed May 8, 2015).
4.73	Indenture, dated February 20, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Subsidiary Guarantors, and First Union National Bank, NA, as Trustee (incorporated by reference to Exhibit 99.2 to the Form 8-K filed by TEPPCO Partners, L.P. on February 20, 2002).
4.74	Supplemental Indenture, dated June 27, 2002, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Jonah Gas Gathering Company, as Initial Subsidiary Guarantors, Val Verde Gas Gathering Company, L.P., as New Subsidiary Guarantor, and Wachovia Bank, National Association, formerly known as First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.6 to the Form 10-Q filed by TEPPCO Partners, L.P. on August 14, 2002).
4.75	Full Release of Guarantee, dated July 31, 2006, by Wachovia Bank, National Association, as Trustee, in favor of Jonah Gas Gathering Company (incorporated by reference to Exhibit 4.8 to the Form 10-Q filed by TEPPCO Partners, L.P. on November 7, 2006).
4.76	Fourth Supplemental Indenture, dated June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P., Val Verde Gas Gathering Company, L.P., TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.77	Sixth Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.12 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.78	Seventh Supplemental Indenture, dated March 27, 2008, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.13 to the Form 10-Q filed by TEPPCO Partners, L.P. on May 8, 2008).
4.79	Eighth Supplemental Indenture, dated October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas

Gathering Company, L.P., as Subsidiary Guarantors, and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).

147

Table of Contents

4.80	Full Release of Guarantee, dated November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.64 to Form 10-K filed March 1, 2010).
4.81	Indenture, dated May 14, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 99.1 of the Form 8-K filed by TEPPCO Partners, L.P. on May 15, 2007).
4.82	First Supplemental Indenture, dated May 18, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on May 18, 2007).
4.83	Second Supplemental Indenture, dated as of June 30, 2007, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, Limited Partnership, TCTM, L.P., TEPPCO Midstream Companies, L.P. and Val Verde Gas Gathering Company, L.P., as Existing Subsidiary Guarantors, TE Products Pipeline Company, LLC and TEPPCO Midstream Companies, LLC, as New Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TE Products Pipeline Company, LLC on July 6, 2007).
4.84	Third Supplemental Indenture, dated as of October 27, 2009, by and among TEPPCO Partners, L.P., as Issuer, TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P., as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.2 to the Form 8-K filed by TEPPCO Partners, L.P. on October 28, 2009).
4.85	Full Release of Guarantee, dated as of November 23, 2009, of TE Products Pipeline Company, LLC, TCTM, L.P., TEPPCO Midstream Companies, LLC and Val Verde Gas Gathering Company, L.P. by The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.70 to Form 10-K filed March 1, 2010).
4.86	Registration Rights Agreement by and between Enterprise Products Partners L.P. and Oiltanking Holding Americas, Inc. dated as of October 1, 2014 (incorporated by reference to Exhibit 4.1 to Form 8-K filed October 1, 2014).
10.1***	Enterprise Products 1998 Long-Term Incentive Plan (Amended and Restated as of February 23, 2010) (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 26, 2010).
10.2***	Form of Employee Restricted Unit Grant Award under the Enterprise Products 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Form 10-Q filed August 9, 2010).
10.3***	2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (incorporated by reference to Annex A to Definitive Proxy Statement filed August 26, 2013).
10.4***	Form of Employee Phantom Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Form 10-K filed February 24, 2017).
10.5	Eighth Amended and Restated Administrative Services Agreement, effective as of February 13, 2015, by and among Enterprise Products Company, EPCO Holdings, Inc., Enterprise Products Holdings LLC, Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC and the Oiltanking Parties named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed February 13, 2015).
10.6	364-Day Revolving Credit Agreement, dated as of September 12, 2018, among Enterprise Products Operating LLC, the Lenders party thereto, and Citibank, N.A. as Administrative Agent (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 12, 2018).
10.7	

Guaranty Agreement, dated as of September 12, 2018, by Enterprise Products Partners L.P. in favor of Citibank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 12, 2018).

148

Table of Contents

10.8	Revolving Credit Agreement, dated as of September 13, 2017, among Enterprise Products Operating LLC, the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Bank, Ltd. and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Syndication Agents, and Barclays Bank PLC, Royal Bank of Canada, Sumitomo Mitsui Banking Corporation, SunTrust Bank, The Bank of Nova Scotia and The Toronto-Dominion Bank, New York Branch, as Co-Documentation Agents (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 15, 2017).
10.9	Guaranty Agreement, dated as of September 13, 2017, by Enterprise Products Partners L.P. in favor of Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.4 to Form 8-K filed September 15, 2017).
10.10	Liquidity Option Agreement, dated as of October 1, 2014, between Enterprise Products Partners, L.P., Oiltanking Holding Americas, Inc., and Marquard & Bahls AG (incorporated by reference to Exhibit 10.3 to Form 8-K filed October 1, 2014).
10.11	Support Agreement, dated as of November 11, 2014, by and among Enterprise Products Partners L.P., Enterprise Products Operating LLC and Oiltanking Partners, L.P. (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 12, 2014).
10.12***	EPD PubCo Unit I L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.17 to Form 10-K filed February 24, 2017).
10.13***	EPD PubCo Unit II L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.18 to Form 10-K filed February 24, 2017).
10.14***	EPD PrivCo Unit I L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.19 to Form 10-K filed February 24, 2017).
10.15***	EPD PubCo Unit III L.P. Amended and Restated Agreement of Limited Partnership dated November 3, 2016 (incorporated by reference to Exhibit 10.20 to Form 10-K filed February 24, 2017).
10.16***	EPD 2018 Unit IV L.P. Agreement of Limited Partnership dated December 3, 2018 (incorporated by reference to Exhibit 10.1 to Form 8-K filed December 6, 2018).
10.17***	EPCO Unit II L.P. Agreement of Limited Partnership dated December 3, 2018 (incorporated by reference to Exhibit 10.2 to Form 8-K filed December 6, 2018).
10.16	Equity Distribution Agreement, dated December 1, 2017, by and among Enterprise Products Partners L.P., Enterprise Products OLPGP, Inc., Enterprise Products Operating LLC and Citigroup Global Markets Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., DNB Markets, Inc., Jefferies LLC, J.P. Morgan Securities LLC, Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, MUFG Securities Americas Inc., Raymond James & Associates, Inc., RBC Capital Markets, LLC, Scotia Capital (USA) Inc., SG Americas Securities, LLC, SMBC Nikko Securities America, Inc., SunTrust Robinson Humphrey, Inc., TD Securities (USA) LLC, UBS Securities LLC, USCA Securities LLC and Wells Fargo Securities, LLC. (incorporated by reference to Exhibit 1.1 to Form 8-K filed December 1, 2017).
10.17***	Separation Agreement dated effective as of September 11, 2018 by and between Enterprise Products Company and Bryan F. Bulawa (incorporated by reference to Exhibit 10.3 to Form 8-K filed September 12, 2018).
21.1#	List of consolidated subsidiaries as of February 1, 2019.
23.1#	Consent of Deloitte & Touche LLP.
31.1#	Sarbanes-Oxley Section 302 certification of A. James Teague for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2018.
31.2#	Sarbanes-Oxley Section 302 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2018.
32.1#	Sarbanes-Oxley Section 906 certification of A. James Teague for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2018.
32.2#	

Sarbanes-Oxley Section 906 certification of W. Randall Fowler for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2018.

149

Table of Contents

101.CAL#	XBRL Calculation Linkbase Document
101.DEF#	XBRL Definition Linkbase Document
101.INS#	XBRL Instance Document
101.LAB#	XBRL Labels Linkbase Document
101.PRE#	XBRL Presentation Linkbase Document
101.SCH#	XBRL Schema Document

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file numbers for Enterprise Products Partners L.P., Enterprise GP Holdings L.P, TEPPCO Partners, L.P. and TE Products Pipeline Company, LLC are 1-14323, 1-32610, 1-10403 and 1-13603, respectively.

*** Identifies management contract and compensatory plan arrangements.

Filed with this report.

ITEM 16. FORM 10-K SUMMARY.

Not included.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on March 1, 2019.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products Holdings LLC, as General Partner

By: /s/ R. Daniel Boss
Name: R. Daniel Boss
Title: Senior Vice President – Accounting and Risk Control of the General Partner

By: /s/ Michael W. Hanson
Name: Michael W. Hanson
Title: Vice President and Principal Accounting Officer of the General Partner

Table of Contents

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated below on March 1, 2019.

Signature	Title (Position with Enterprise Products Holdings LLC)
/s/ Randa Duncan Williams Randa Duncan Williams	Director and Chairman of the Board
/s/ Richard H. Bachmann Richard H. Bachmann	Director and Vice-Chairman of the Board
/s/ A. James Teague A. James Teague	Director and Chief Executive Officer
/s/ W. Randall Fowler W. Randall Fowler	Director, President and Chief Financial Officer
/s/ Harry P. Weitzel Harry P. Weitzel	Director and Senior Vice President, General Counsel and Secretary
/s/ Carin M. Barth Carin M. Barth	Director
/s/ Murray E. Brasseux Murray E. Brasseux	Director
/s/ James T. Hackett James T. Hackett	Director
/s/ Charles E. McMahen Charles E. McMahen	Director
/s/ William C. Montgomery William C. Montgomery	Director
/s/ John R. Rutherford John R. Rutherford	Director
/s/ Richard S. Snell Richard S. Snell	Director
/s/ R. Daniel Boss R. Daniel Boss	Senior Vice President – Accounting and Risk Control
/s/ Michael W. Hanson Michael W. Hanson	Vice President and Principal Accounting Officer

Table of Contents

Item 8. Financial Statements and Supplementary Data.

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

F-1

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enterprise Products Holdings LLC and
Unitholders of Enterprise Products Partners L.P.
Houston, Texas

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the “Company”) as of December 31, 2018 and 2017, the related statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
March 1, 2019

We have served as the Company’s auditor since 1997.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$344.8	$5.1
Restricted cash	65.3	65.2
Accounts receivable – trade, net of allowance for doubtful accounts of $11.5 at December 31, 2018 and $12.1 at December 31, 2017	3,659.1	4,358.4
Accounts receivable – related parties	3.5	1.8
Inventories	1,522.1	1,609.8
Derivative assets (see Note 14)	154.4	153.4
Prepaid and other current assets	311.5	312.7
Total current assets	6,060.7	6,506.4
Property, plant and equipment, net	38,737.6	35,620.4
Investments in unconsolidated affiliates	2,615.1	2,659.4
Intangible assets, net of accumulated amortization of $1,735.1 at December 31, 2018 and $1,564.8 at December 31, 2017 (see Note 6)	3,608.4	3,690.3
Goodwill (see Note 6)	5,745.2	5,745.2
Other assets	202.8	196.4
Total assets	$56,969.8	$54,418.1
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 7)	$1,500.1	$2,855.0
Accounts payable – trade	1,102.8	801.7
Accounts payable – related parties	140.2	127.3
Accrued product payables	3,475.8	4,566.3
Accrued interest	395.6	358.0
Derivative liabilities (see Note 14)	148.2	168.2
Other current liabilities	404.8	418.6
Total current liabilities	7,167.5	9,295.1
Long-term debt (see Note 7)	24,678.1	21,713.7
Deferred tax liabilities	80.4	58.5
Other long-term liabilities	751.6	578.4
Commitments and contingencies (see Note 17)		
Equity: (see Note 8)		
Partners' equity:		
Limited partners:		
Common units (2,184,869,029 units outstanding at December 31, 2018 and 2,161,089,479 units outstanding at December 31, 2017)	23,802.6	22,718.9
Accumulated other comprehensive income (loss)	50.9	(171.7)
Total partners' equity	23,853.5	22,547.2
Noncontrolling interests	438.7	225.2
Total equity	24,292.2	22,772.4
Total liabilities and equity	$56,969.8	$54,418.1

See Notes to Consolidated Financial Statements.
F-3

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For the Year Ended December 31,		
	2018	2017	2016
Revenues:			
Third parties	$36,426.5	$29,196.5	$22,965.6
Related parties	107.7	45.0	56.7
Total revenues (see Note 9)	36,534.2	29,241.5	23,022.3
Costs and expenses:			
Operating costs and expenses:			
Third parties	29,991.2	24,444.7	18,539.5
Related parties	1,406.1	1,112.8	1,104.0
Total operating costs and expenses	31,397.3	25,557.5	19,643.5
General and administrative costs:			
Third parties	77.4	59.6	47.0
Related parties	130.9	121.5	113.1
Total general and administrative costs	208.3	181.1	160.1
Total costs and expenses (see Note 10)	31,605.6	25,738.6	19,803.6
Equity in income of unconsolidated affiliates	480.0	426.0	362.0
Operating income	5,408.6	3,928.9	3,580.7
Other income (expense):			
Interest expense	(1,096.7)	(984.6)	(982.6)
Change in fair market value of Liquidity Option Agreement (see Note 17)	(56.1)	(64.3)	(24.5)
Gain on step acquisition of unconsolidated affiliate (see Note 12)	39.4	--	--
Other, net	3.6	1.3	2.8
Total other expense, net	(1,109.8)	(1,047.6)	(1,004.3)
Income before income taxes	4,298.8	2,881.3	2,576.4
Provision for income taxes (see Note 16)	(60.3)	(25.7)	(23.4)
Net income	4,238.5	2,855.6	2,553.0
Net income attributable to noncontrolling interests (see Note 8)	(66.1)	(56.3)	(39.9)
Net income attributable to limited partners	$4,172.4	$2,799.3	$2,513.1
Earnings per unit: (see Note 11)			
Basic earnings per unit	$1.91	$1.30	$1.20
Diluted earnings per unit	$1.91	$1.30	$1.20

See Notes to Consolidated Financial Statements.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For the Year Ended December 31,		
	2018	2017	2016
Net income	$4,238.5	$2,855.6	$2,553.0
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity derivative instruments:			
Changes in fair value of cash flow hedges	293.2	(38.5)	(193.8)
Reclassification of losses (gains) to net income	(130.4)	112.2	53.4
Interest rate derivative instruments:			
Changes in fair value of cash flow hedges	22.2	(5.7)	42.3
Reclassification of losses to net income	38.1	40.4	37.4
Total cash flow hedges	223.1	108.4	(60.7)
Other	(0.5)	(0.1)	(0.1)
Total other comprehensive income (loss)	222.6	108.3	(60.8)
Comprehensive income	4,461.1	2,963.9	2,492.2
Comprehensive income attributable to noncontrolling interests	(66.1)	(56.3)	(39.9)
Comprehensive income attributable to limited partners	$4,395.0	$2,907.6	$2,452.3

See Notes to Consolidated Financial Statements.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For the Year Ended December 31,		
	2018	2017	2016
Operating activities:			
Net income	$4,238.5	$2,855.6	$2,553.0
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	1,791.6	1,644.0	1,552.0
Asset impairment and related charges	50.5	49.8	53.5
Equity in income of unconsolidated affiliates	(480.0)	(426.0)	(362.0)
Distributions received on earnings from unconsolidated affiliates	479.4	433.7	380.5
Net gains attributable to asset sales (see Note 19)	(28.7)	(10.7)	(2.5)
Deferred income tax expense	21.4	6.1	6.6
Change in fair market value of derivative instruments	17.8	22.8	45.0
Change in fair market value of Liquidity Option Agreement	56.1	64.3	24.5
Gain on step acquisition of unconsolidated affiliate	(39.4)	--	--
Net effect of changes in operating accounts (see Note 19)	16.2	32.2	(180.9)
Other operating activities	2.9	(5.5)	(2.9)
Net cash flows provided by operating activities	6,126.3	4,666.3	4,066.8
Investing activities:			
Capital expenditures	(4,223.2)	(3,101.8)	(2,984.1)
Cash used for business combinations, net of cash received (see Note 12)	(150.6)	(198.7)	(1,000.0)
Investments in unconsolidated affiliates	(113.6)	(50.5)	(138.8)
Distributions received for return of capital from unconsolidated affiliates	50.0	49.3	71.0
Proceeds from asset sales (see Note 19)	161.2	40.1	46.5
Other investing activities	(5.4)	(24.5)	(0.4)
Cash used in investing activities	(4,281.6)	(3,286.1)	(4,005.8)
Financing activities:			
Borrowings under debt agreements	79,588.7	69,315.3	62,813.9
Repayments of debt	(77,957.1)	(68,459.6)	(61,672.6)
Debt issuance costs	(49.1)	(24.1)	(10.6)
Monetization of interest rate derivative instruments (see Note 14)	22.1	30.6	6.1
Cash distributions paid to limited partners (see Note 8)	(3,726.9)	(3,569.9)	(3,300.5)
Cash payments made in connection with distribution equivalent rights	(17.7)	(15.1)	(11.7)
Cash distributions paid to noncontrolling interests (see Note 8)	(81.6)	(49.2)	(47.4)
Cash contributions from noncontrolling interests (see Note 8)	238.1	0.4	20.4
Net cash proceeds from the issuance of common units	538.4	1,073.4	2,542.8
Common units acquired in connection with buyback program (see Note 8)	(30.8)	--	--
Other financing activities	(29.0)	(29.3)	(18.7)
Cash provided by (used in) financing activities	(1,504.9)	(1,727.5)	321.7
Net change in cash and cash equivalents, including restricted cash	339.8	(347.3)	382.7
Cash and cash equivalents, including restricted cash, January 1	70.3	417.6	34.9
Cash and cash equivalents, including restricted cash, December 31	$410.1	$70.3	$417.6

See Notes to Consolidated Financial Statements.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 8 for Unit History, Accumulated Other Comprehensive Income (Loss) and Noncontrolling Interests)
(Dollars in millions)

	Partners' Equity			
	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance, December 31, 2015	$20,514.3	$ (219.2)	$ 206.0	$20,501.1
Net income	2,513.1	--	39.9	2,553.0
Cash distributions paid to limited partners	(3,300.5)	--	--	(3,300.5)
Cash payments made in connection with distribution equivalent rights	(11.7)	--	--	(11.7)
Cash distributions paid to noncontrolling interests	--	--	(47.4)	(47.4)
Cash contributions from noncontrolling interests	--	--	20.4	20.4
Net cash proceeds from the issuance of common units	2,542.8	--	--	2,542.8
Amortization of fair value of equity-based awards	90.2	--	--	90.2
Cash flow hedges	--	(60.7)	--	(60.7)
Other	(21.2)	(0.1)	0.1	(21.2)
Balance, December 31, 2016	22,327.0	(280.0)	219.0	22,266.0
Net income	2,799.3	--	56.3	2,855.6
Cash distributions paid to limited partners	(3,569.9)	--	--	(3,569.9)
Cash payments made in connection with distribution equivalent rights	(15.1)	--	--	(15.1)
Cash distributions paid to noncontrolling interests	--	--	(49.2)	(49.2)
Cash contributions from noncontrolling interests	--	--	0.4	0.4
Net cash proceeds from the issuance of common units	1,073.4	--	--	1,073.4
Common units issued in connection with employee compensation	33.7	--	--	33.7
Amortization of fair value of equity-based awards	99.0	--	--	99.0
Cash flow hedges	--	108.4	--	108.4
Other	(28.5)	(0.1)	(1.3)	(29.9)
Balance, December 31, 2017	22,718.9	(171.7)	225.2	22,772.4
Net income	4,172.4	--	66.1	4,238.5
Cash distributions paid to limited partners	(3,726.9)	--	--	(3,726.9)
Cash payments made in connection with distribution equivalent rights	(17.7)	--	--	(17.7)
Cash distributions paid to noncontrolling interests	--	--	(81.6)	(81.6)
Cash contributions from noncontrolling interests	--	--	238.1	238.1
Net cash proceeds from the issuance of common units	538.4	--	--	538.4
Common units issued in connection with employee compensation	39.1	--	--	39.1
Common units issued in connection with land acquisition	30.0	--	--	30.0
Common units acquired in connection with buyback program	(30.8)	--	--	(30.8)
Amortization of fair value of equity-based awards	104.7	--	--	104.7
Cash flow hedges	--	223.1	--	223.1

Other	(25.5)	(0.5)	(9.1)	(35.1)
Balance, December 31, 2018	$23,802.6	$ 50.9	$ 438.7	$24,292.2

See Notes to Consolidated Financial Statements.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

With the exception of per unit amounts, or as noted within the context of each disclosure, the dollar amounts presented in the tabular data within these disclosures are stated in millions of dollars.

KEY REFERENCES USED IN THESE
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 Directors (the "Board") of Enterprise GP; (ii) Richard H. Bachmann, who is also a director and Vice Chairman of the Board of Enterprise GP; and (iii) Dr. Ralph S. Cunningham, who is also an advisory director of Enterprise GP. Ms. Duncan Williams and Mr. Bachmann also currently serve as managers of Dan Duncan LLC along with W. Randall Fowler, who is also a director and the President and Chief Financial Officer of Enterprise GP.

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. Duncan Williams, who serves as Chairman of EPCO; (ii) Dr. Cunningham, who serves as Vice Chairman of EPCO; and (iii) Mr. Bachmann, who serves as the President and Chief Executive Officer of EPCO. Ms. Duncan Williams and Mr. Bachmann also currently serve as directors of EPCO along with Mr. Fowler, who is also the Executive Vice President and Chief Financial Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 31.9% of our limited partner interests at December 31, 2018.

Note 1. Partnership Organization and Operations

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 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 the 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 export and import terminals (including those used to export liquefied petroleum gases, or "LPG," and ethane); crude oil gathering, transportation, storage, and export and import terminals; petrochemical and refined products transportation, storage, export and import terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems. Our assets currently include approximately 49,200 miles of pipelines; 260 million barrels ("MMBbls") of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 billion cubic feet ("Bcf") of natural gas storage capacity. All statistical data (e.g., pipeline mileage, processing capacity and similar operating metrics) in these notes to consolidated financial statements are unaudited.

F-8

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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. We, Enterprise GP, EPCO and Dan Duncan LLC are affiliates under the collective common control of the DD LLC Trustees and the EPCO Trustees. 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. See Note 15 for information regarding related party matters.

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) Petrochemical & Refined Products Services. See Note 10 for additional information regarding our business segments.

Note 2. Summary of Significant Accounting Policies

Allowance for Doubtful Accounts

Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts, including those related to natural gas imbalances. Our procedure for estimating the allowance for doubtful accounts is based on: (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research and (iii) the levels of credit we grant to customers. In addition, we may increase the allowance for doubtful accounts in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses. The following table presents our allowance for doubtful accounts activity for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Balance at beginning of period	$12.1	$11.3	$12.1
Charged to costs and expenses	0.7	2.7	2.3
Deductions	(1.3)	(1.9)	(3.1)
Balance at end of period	$11.5	$12.1	$11.3

See “Credit Risk” in Note 18 for additional information.

Cash, Cash Equivalents and Restricted Cash

Cash and cash equivalents represent unrestricted cash on hand and highly liquid investments with original maturities of less than three months from the date of purchase. Restricted cash represents amounts held in segregated bank accounts by our clearing brokers as margin in support of our commodity derivative instruments portfolio and related physical purchases and sales of natural gas, NGLs, crude oil and refined products. Additional cash may be restricted to maintain our commodity derivative instruments portfolio as prices fluctuate or margin requirements change. The following table provides a reconciliation of cash and cash equivalents, and restricted cash reported within the Consolidated Balance Sheets that sum to the total of the amounts shown in the Statements of Consolidated Cash Flows.

	December 31,	
	2018	2017
Cash and cash equivalents	$344.8	$5.1
Restricted cash	65.3	65.2
Total cash, cash equivalents and restricted cash shown in the Statements of Consolidated Cash Flows	$410.1	$70.3

The balance of restricted cash at December 31, 2018 consisted of initial margin requirements of $69.6 million partially offset by positive variation margin of $4.3 million. The initial margin requirements will be returned to us as the related derivative instruments are settled. See Note 14 for information regarding our derivative instruments and hedging activities.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidation Policy

Our consolidated financial statements include our accounts and those of our majority-owned subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. We also consolidate other entities and ventures in which we possess a controlling financial interest as well as partnership interests where we are the sole general partner of the partnership. We evaluate our financial interests in business enterprises to determine if they represent variable interest entities where we are the primary beneficiary. If such criteria are met, we consolidate the financial statements of such businesses with those of our own. Third party or affiliate ownership interests in our controlled subsidiaries are presented as noncontrolling interests. See Note 8 for information regarding noncontrolling interests.

If the entity is organized as a limited partnership or limited liability company and maintains separate ownership accounts, we account for our investment using the equity method if our ownership interest is between 3% and 50%, unless our interest is so minor that we have virtually no influence over the investee’s operating and financial policies. For all other types of investments, we apply the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the investee’s operating and financial policies. In consolidation, we eliminate our proportionate share of profits and losses from transactions with equity method unconsolidated affiliates to the extent such amounts remain on our Consolidated Balance Sheets (or those of our equity method investments) in inventory or similar accounts.

Contingencies

Certain conditions may exist as of the date our consolidated financial statements are issued, which may result in a loss to us but which will only be resolved when one or more future events occur or fail to occur. Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the need for accounting recognition or disclosure of these contingencies, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in such proceedings, our management and legal counsel evaluate the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

We accrue an undiscounted liability for those contingencies where the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. We do not record a contingent liability when the likelihood of loss is probable but the amount cannot be reasonably estimated or when the likelihood of loss is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is reasonably possible and the impact would be material to our consolidated financial statements, we disclose the nature of the contingency and, where feasible, an estimate of the possible loss or range of loss.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed. See Note 17 for additional information regarding our contingencies.

Current Assets and Current Liabilities

We present, as individual captions in our Consolidated Balance Sheets, all components of current assets and current liabilities that exceed 5% of total current assets and current liabilities, respectively.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Derivative Instruments

We use derivative instruments such as futures, swaps, forward contracts and other arrangements to manage price risks associated with inventories, firm commitments, interest rates and certain anticipated future commodity transactions. To qualify for hedge accounting, the hedged item must expose us to risk and the related derivative instrument must reduce the exposure to that risk and meet specific hedge documentation requirements related to designation dates, expectations for hedge effectiveness and the probability that hedged future transactions will occur as forecasted. We formally designate derivative instruments as hedges and document and assess their effectiveness at inception of the hedge and on a monthly basis thereafter. Forecasted transactions are evaluated for the probability of occurrence and are periodically back-tested once the forecasted period has passed to determine whether similarly forecasted transactions are probable of occurring in the future.

We are required to recognize derivative instruments at fair value as either assets or liabilities on our Consolidated Balance Sheets unless such instruments meet certain normal purchase/normal sale criteria. While all derivatives are required to be reported at fair value on the balance sheet, changes in fair value of derivative instruments are reported in different ways, depending on the nature and effectiveness of the hedging activities to which they relate. After meeting specified conditions, a qualified derivative may be designated as a total or partial hedge of:

§ Changes in the fair value of a recognized asset or liability, or an unrecognized firm commitment – In a fair value hedge, gains and losses for both the derivative instrument and the hedged item are recognized in income during the period of change.

§ Variable cash flows of a forecasted transaction – In a cash flow hedge, the change in the fair value of the hedge is reported in other comprehensive income (loss) and is reclassified to earnings when the forecasted transaction affects earnings.

An effective hedge relationship is one in which the change in fair value of a derivative instrument can be expected to offset 80% to 125% of the changes in fair value of a hedged item at inception and throughout the life of the hedging relationship. The effective portion of a hedge relationship is the amount by which the derivative instrument exactly offsets the change in fair value of the hedged item during the reporting period. Conversely, ineffectiveness represents the change in the fair value of the derivative instrument that does not exactly offset the change in the fair value of the hedged item. Any ineffectiveness associated with a fair value hedge is recognized in earnings immediately. Ineffectiveness can be caused by, among other things, changes in the timing of forecasted transactions or a mismatch of terms between the derivative instrument and the hedged item.

A contract designated as a cash flow hedge of an anticipated transaction that is not probable of occurring is immediately recognized in earnings.

Certain of our derivative instruments do not qualify for hedge accounting treatment; therefore, these instruments are accounted for using mark-to-market accounting.

For certain physical forward commodity derivative contracts, we apply the normal purchase/normal sale exception, whereby changes in the mark-to-market values of such contracts are not recognized in income. As a result, the revenues and expenses associated with such physical transactions are recognized during the period when volumes are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically back-tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the future. See Note 14 for additional information regarding our derivative instruments.

F-11

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Environmental Costs

Environmental costs for remediation are accrued based on estimates of known remediation requirements. Such accruals are based on management's best estimate of the ultimate cost to remediate a site and are adjusted as further information and circumstances develop. Those estimates may change substantially depending on information about the nature and extent of contamination, appropriate remediation technologies and regulatory approvals. Expenditures to mitigate or prevent future environmental contamination are capitalized. Ongoing environmental compliance costs are charged to expense as incurred. In accruing for environmental remediation liabilities, costs of future expenditures for environmental remediation are not discounted to their present value, unless the amount and timing of the expenditures are fixed or reliably determinable. At December 31, 2018, none of our estimated environmental remediation liabilities were discounted to present value since the ultimate amount and timing of cash payments for such liabilities were not readily determinable.

The following table presents the activity of our environmental reserves for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Balance at beginning of period	$11.6	$11.9	$13.0
Charged to costs and expenses	8.2	12.1	7.0
Acquisition-related additions and other	1.7	1.7	0.5
Deductions	(14.6)	(14.1)	(8.6)
Balance at end of period	$6.9	$11.6	$11.9

At December 31, 2018 and 2017, $3.2 million and $5.6 million, respectively, of our environmental reserves were classified as current liabilities.

Estimates

Preparing our consolidated financial statements in conformity with U.S. generally accepted accounting principles ("GAAP") requires us to make estimates that affect amounts presented in the financial statements. Our most significant estimates relate to (i) the useful lives and depreciation/amortization methods used for fixed and identifiable intangible assets; (ii) measurement of fair value and projections used in impairment testing of fixed and intangible assets (including goodwill); (iii) contingencies; and (iv) revenue and expense accruals.

Actual results could differ materially from our estimates. On an ongoing basis, we review our estimates based on currently available information. Any changes in the facts and circumstances underlying our estimates may require us to update such estimates, which could have a material impact on our consolidated financial statements.

Fair Value Measurements

Our fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk, in the principal market of the asset or liability at a specified measurement date. Recognized valuation techniques employ inputs such as contractual prices, quoted market prices or rates, operating costs, discount factors and business growth rates. These inputs may be either readily observable, corroborated by market data or generally unobservable. In developing our estimates of fair value, we endeavor to utilize the best information available and apply market-based data to the highest extent possible. Accordingly, we utilize valuation techniques (such as the market approach) that maximize the use of observable inputs and minimize the use of unobservable inputs.

A three-tier hierarchy has been established that classifies fair value amounts recognized in the financial statements based on the observability of inputs used to estimate such fair values. The hierarchy considers fair value amounts based on observable inputs (Levels 1 and 2) to be more reliable and predictable than those based primarily on unobservable inputs (Level 3). At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

§ Level 1 fair values are based on quoted prices, which are available in active markets for identical assets or liabilities as of the measurement date. Active markets are defined as those in which transactions for identical assets or liabilities occur with sufficient frequency so as to provide pricing information on an ongoing basis (e.g., the New York Mercantile Exchange ("NYMEX")). Our Level 1 fair values consist of financial assets and liabilities such as exchange-traded commodity derivative instruments.

§ Level 2 fair values are based on pricing inputs other than quoted prices in active markets (as reflected in Level 1 fair values) and are either directly or indirectly observable as of the measurement date. Level 2 fair values include instruments that are valued using financial models or other appropriate valuation methodologies. Such financial models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, the time value of money, volatility factors, current market and contractual prices for the underlying instruments and other relevant economic measures. Substantially all of these assumptions (i) are observable in the marketplace throughout the full term of the instrument; (ii) can be derived from observable data; or (iii) are validated by inputs other than quoted prices (e.g., interest rate and yield curves at commonly quoted intervals). Our Level 2 fair values primarily consist of commodity derivative instruments such as forwards, swaps and other instruments transacted on an exchange or over-the-counter and interest rate derivative instruments. The fair values of these derivative instruments are based on observable price quotes for similar products and locations. The fair value of our interest rate derivatives are determined using financial models that incorporate the implied forward LIBOR yield curve for the same period as the future interest rate swap settlements.

§ Level 3 fair values are based on unobservable inputs. Unobservable inputs are used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. Unobservable inputs reflect management's ideas about the assumptions that market participants would use in pricing an asset or liability (including assumptions about risk). Unobservable inputs are based on the best information available to us in the circumstances, which might include our internally developed data. Level 3 inputs are typically used in connection with internally developed valuation methodologies where we make our best estimate of an instrument's fair value. With regards to commodity derivatives, our Level 3 fair values primarily consist of the following commodity derivative instruments which are used to hedge our various inventories and transportation capacities: (i) NGL-based contracts with terms greater than one year; (ii) crude, natural gas and refined products-based contracts with terms greater than 36 months; (iii) over-the-counter options; and (iv) exchange traded options with terms greater than one year. In addition, we often rely on price quotes from reputable brokers who publish price quotes on certain products and compare these prices to other reputable brokers for the same products in the same markets whenever possible. These prices, when combined with data from our commodity derivative instruments, are used in our models to determine the fair value of such instruments.

Transfers within the fair value hierarchy routinely occur for certain term contracts as prices and other inputs used for the valuation of future delivery periods become more observable with the passage of time. Other transfers are made periodically in response to changing market conditions that affect liquidity, price observability and other inputs used in determining valuations. We deem any such transfers to have occurred at the end of the quarter in which they transpired. There were no transfers between Level 1 and 2 during the years ended December 31, 2018 and 2017.

We have a risk management policy that covers our Level 3 commodity derivatives. Governance and oversight of risk management activities for these commodities are provided by our Chief Executive Officer with guidance and support from a risk management committee ("RMC") that meets quarterly (or on a more frequent basis, if needed). Members of executive management attend the RMC meetings, which are chaired by the head of our commodities risk control group. This group is responsible for preparing and distributing daily reports and risk analysis to members of the RMC and other appropriate members of management. These reports include mark-to-market valuations with the one-day and month-to-date changes in fair values. This group also develops and validates the forward commodity price curves used to estimate the fair values of our Level 3 commodity derivatives. These forward curves incorporate published indexes, market quotes and other observable inputs to the extent available.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Impairment Testing for Goodwill

Our goodwill amounts are assessed for impairment on a routine annual basis or when impairment indicators are present. If such indicators occur (e.g., the loss of a significant customer or technological obsolescence of assets), the estimated fair value of the reporting unit to which the goodwill is assigned is determined and compared to its carrying value. If the fair value of the reporting unit is less than its carrying value including associated goodwill amounts, a non-cash impairment charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value.

Our reporting unit estimated fair values are based on assumptions regarding the future economic prospects of the businesses that comprise each reporting unit. Such assumptions include: (i) discrete financial forecasts for the assets classified within the reporting unit, which, in turn, rely on management's estimates of operating margins, throughput volumes and similar factors; (ii) long-term growth rates for cash flows beyond the discrete forecast period; and (iii) appropriate discount rates. We believe the assumptions we use in estimating reporting unit fair values are consistent with those that would be employed by market participants in their fair value estimation process. Based on our most recent goodwill impairment test at December 31, 2018, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

See Note 6 for additional information regarding goodwill.

Impairment Testing for Long-Lived Assets

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Long-lived assets with carrying values that are not expected to be recovered through future cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is deemed not recoverable if it exceeds the sum of undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset's carrying value exceeds the sum of its undiscounted cash flows, a non-cash asset impairment charge equal to the excess of the asset's carrying value over its estimated fair value is recorded. Fair value is defined as the price that would be received to sell an asset or be paid to transfer a liability in an orderly transaction between market participants at a specified measurement date. We measure fair value using market price indicators or, in the absence of such data, appropriate valuation techniques. See Note 14 for information regarding non-cash impairment charges related to long-lived assets.

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment to determine whether there are events or changes in circumstances that indicate there is a loss in value of the investment attributable to an other than temporary decline. Examples of such events or changes in circumstances include continuing operating losses of the entity and/or long-term negative changes in the entity's industry. In the event we determine that the loss in value of an investment is an other than temporary decline, we record a non-cash impairment charge to equity earnings to adjust the carrying value of the investment to its estimated fair value. There were not any non-cash impairment charges related to our equity method investments during the years ended December 31, 2018, 2017 and 2016. See Note 5 for information regarding our equity method investments.

Inventories

Inventories primarily consist of NGLs, petrochemicals, refined products, crude oil and natural gas volumes that are valued at the lower of cost or net realizable value. We capitalize, as a cost of inventory, shipping and handling charges (e.g., pipeline transportation and storage fees) and other related costs associated with purchased volumes. As volumes are sold and delivered out of inventory, the cost of these volumes (including freight-in charges that have been capitalized as part of inventory cost) are charged to operating costs and expenses. Shipping and handling fees associated with products we sell and deliver to customers are charged to operating costs and expenses as incurred. See Note 3 for additional information regarding our inventories.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Expenditures for additions, improvements and other enhancements to property, plant and equipment are capitalized, and minor replacements, maintenance, and repairs that do not extend asset life or add value are charged to expense as incurred. When property, plant and equipment assets are retired or otherwise disposed of, the related cost and accumulated depreciation is removed from the accounts and any resulting gain or loss is included in results of operations for the respective period.

We capitalize interest costs incurred on funds used to construct property, plant and equipment while the asset is in its construction phase. The capitalized interest is recorded as part of the asset to which it relates and is amortized over the asset's estimated useful life as a component of depreciation expense. When capitalized interest is recorded, it reduces interest expense from what it would be otherwise.

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. The majority of our property, plant and equipment is depreciated using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. With respect to midstream energy assets such as natural gas gathering systems that are reliant upon a specific natural resource basin for throughput volumes, the anticipated useful economic life of such assets may be limited by the estimated life of the associated natural resource basin from which the assets derive benefit. Our forecast of the remaining life for the applicable resource basins is based on several factors, including information published by the U.S. Energy Information Administration. Where appropriate, we use other depreciation methods (generally accelerated) for tax purposes.

Leasehold improvements are recorded as a component of property, plant and equipment. The cost of leasehold improvements is charged to earnings using the straight-line method over the shorter of (i) the remaining lease term or (ii) the estimated useful lives of the improvements. We consider renewal terms that are deemed reasonably assured when estimating remaining lease terms.

Our assumptions regarding the useful economic lives and residual values of our assets may change in response to new facts and circumstances, which would prospectively impact our depreciation expense amounts. Examples of such circumstances include, but are not limited to: (i) changes in laws and regulations that limit the estimated economic life of an asset; (ii) changes in technology that render an asset obsolete; (iii) changes in expected salvage values or (iv) significant changes in the forecast life of the applicable resource basins, if any.

Certain of our plant operations entail periodic planned outages for major maintenance activities. These planned shutdowns typically result in significant expenditures, which are principally comprised of amounts paid to third parties for materials, contract services and related items. We use the expense-as-incurred method for our planned major maintenance activities for plant operations; however, the cost of annual planned major maintenance projects for such plants are deferred and recognized on a straight-line basis over the remaining portion of the fiscal year in which the maintenance occurred. With regard to the planned major maintenance activities on our marine transportation assets and underground storage caverns, we use the deferral method to account for such costs. Under this method, major maintenance costs are capitalized and amortized over the period until the next major overhaul or cavern integrity project.

Asset retirement obligations ("AROs") are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. When an ARO is incurred, we record a liability for the ARO and capitalize an equal amount as an increase in the carrying value of the related long-lived asset. ARO amounts are measured at their estimated fair value using expected present value techniques. Over time, the ARO liability is accreted to its present value (through accretion expense) and the capitalized amount is depreciated over the remaining useful life of the related long-lived asset. We will incur a gain or loss to the extent that our ARO liabilities are not settled at their recorded amounts.

See Note 4 for additional information regarding our property, plant and equipment and AROs.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Recent Accounting Developments

Adoption of New Revenue Recognition Policies on January 1, 2018
For periods through December 31, 2017, we accounted for our revenue streams using Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 605, Revenue Recognition. Under ASC 605, we recognized revenue when all of the following criteria were met: (i) persuasive evidence of an exchange arrangement existed between us and the counterparty (e.g., published tariffs), (ii) delivery of products or the rendering of services had occurred, (iii) the price of the products or the fee for services was fixed or determinable and (iv) collectibility of the amount owed by the counterparty was reasonably assured.

We adopted ASC 606, Revenue from Contracts with Customers, on January 1, 2018 using a modified retrospective approach that applied the new revenue recognition standard to existing contracts at the implementation date and any future revenue contracts. As such, our consolidated revenues and related financial information for periods prior to January 1, 2018 were not adjusted and continue to be reported in accordance with ASC 605. We did not record a cumulative effect adjustment upon initially applying ASC 606 since there was no impact on partners' equity upon adoption; however, the extent of our revenue-related disclosures has increased under the new standard.

Due to the large number of individual contracts that were in effect at the implementation date of ASC 606, we evaluated our contracts using a portfolio approach based on the types of products sold or services rendered within our business segments. There are no material differences in the amount or timing of revenues recognized under ASC 606 when compared to ASC 605.

The core principle of ASC 606 is that a company should recognize revenue in a manner that fairly depicts the transfer of goods or services to customers in amounts that reflect the consideration the company expects to receive for those goods or services. We apply this core principle by following five key steps outlined in ASC 606: (i) identify the contract; (ii) identify the performance obligations in the contract; (iii) determine the transaction price; (iv) allocate the transaction price to the performance obligations in the contract; and (v) recognize revenue when (or as) the performance obligation is satisfied. Each of these steps involves management judgment and an analysis of the contract's material terms and conditions.

Substantially all of our revenues are accounted for under ASC 606; however, to a limited extent, some revenues are accounted for under other guidance such as ASC 840, Leases, ASC 845, Nonmonetary Transactions, or ASC 815, Derivatives and Hedging Activities.

Under ASC 606, we recognize revenue when or as we satisfy our performance obligation to the customer. In situations where we have recognized revenue, but have a conditional right to consideration (based on something other than the passage of time) from the customer, we recognize unbilled revenue (a contract asset) on our consolidated balance sheet. Unbilled revenue is reclassified to accounts receivable when we have an unconditional right of payment from the customer. Payments received from customers in advance of the period in which we satisfy a performance obligation are recorded as deferred revenue (a contract liability) on our consolidated balance sheet.

Our revenue streams are derived from the sale of products and providing midstream services. Revenues from the sale of products are recognized at a point in time, which represents the transfer of control (and the satisfaction of our performance obligation under the contract) to the customer. From that point forward, the customer is able to direct the use of, and obtain substantially all the benefits from, its use of the products. With respect to midstream services (e.g., interruptible transportation), we satisfy our performance obligations over time and recognize revenues when the services are provided and the customer receives the benefits based on an output measure of volumes redelivered. We believe this measure is a faithful depiction of the transfer of control for midstream services since there is (i) an insignificant period of time between the receipt of customers' volumes and their subsequent redelivery, and (ii) it is not possible to individually track and differentiate customers' inventories as they traverse our facilities. For stand-ready performance obligations (e.g., a storage capacity reservation contract), we recognize revenues over time on a straight-line basis as time elapses over the term of the contract. We believe that these approaches accurately depict the transfer of benefits to the customer.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Customers are invoiced for products purchased or services rendered when we have an unconditional right to consideration under the associated contract. The consideration we are entitled to invoice may be either fixed, variable or a combination of both. Examples of fixed consideration would be fixed payments from customers under take-or-pay arrangements, storage capacity reservation agreements and firm transportation contracts. Variable consideration represents payments from customers that are based on factors that fluctuate (or vary) based on volumes, prices or both. Examples of variable consideration include interruptible transportation agreements, market-indexed product sales contracts and the value of NGLs we retain under natural gas processing agreements. The terms of our billings are typical of the industry for the products we sell.

Under certain midstream service agreements, customers are required to provide a minimum volume over an agreed-upon period with a provision that allows the customer to make-up any volume shortfalls over an agreed-upon period (referred to as "make-up rights"). Revenue pursuant to such agreements is initially deferred and subsequently recognized when either the make-up rights are exercised, the likelihood of the customer exercising the rights becomes remote, or we are otherwise released from the performance obligation.

Customers may contribute funds to us to help offset the construction costs related to pipeline construction activities and production well tie-ins. Under ASC 605, these amounts were accounted for as contributions in aid of construction costs ("CIACs") and netted against property, plant and equipment. Under ASC 606, these receipts are recognized as additional service revenues over the term of the associated midstream services provided to the customer.

As a practical expedient, for those contracts under which we have the ability to invoice the customer in an amount that corresponds directly with the value of the performance obligation completed to date, we recognize revenue as we have the right to invoice.

See Note 9 regarding our new revenue disclosures.

Lease accounting standard
In February 2016, the FASB issued ASC 842, Leases, which requires substantially all leases to be recorded on the balance sheet. We adopted the new standard on January 1, 2019 and applied it to (i) all new leases entered into after January 1, 2019 and (ii) all existing lease contracts as of January 1, 2019. ASC 842 supersedes existing lease accounting guidance found under ASC 840.

The new standard introduces two lessee accounting models, which result in a lease being classified as either a "finance" or "operating" lease on the basis of whether the lessee effectively obtains control of the underlying asset during the lease term. A lease would be classified as a finance lease if it meets one of five classification criteria, four of which are generally consistent with ASC 840 lease accounting guidance. By default, a lease that does not meet the criteria to be classified as a finance lease will be deemed an operating lease. Regardless of classification, the initial measurement of both lease types will result in the balance sheet recognition of a right-of-use ("ROU") asset (representing a company's right to use the underlying asset for a specified period of time) and a corresponding lease liability. The lease liability will be recognized at the present value of the future lease payments, and the ROU asset will equal the lease liability adjusted for any prepaid rent, lease incentives provided by the lessor, and any indirect costs.

The subsequent measurement of each type of lease varies. For finance leases, a lessee will amortize the ROU asset (generally on a straight-line basis in a manner similar to depreciation) and accrete lease liability (as a component of interest expense). Operating leases will result in the recognition of a single lease expense amount that is recorded on a straight-line basis (or another systematic basis, as appropriate).

ASC 842 will result in changes to the way our operating leases are recorded, presented and disclosed in our consolidated financial statements. Upon adoption of ASC 842 on January 1, 2019, we recognized a ROU asset and a corresponding lease liability based on the present value of then existing operating lease obligations. In addition, there are several key accounting policy elections that we made upon adoption of ASC 842 including:

§ We will not recognize ROU assets and lease liabilities for short-term leases and instead record them in a manner similar to operating leases under legacy lease accounting guidelines. A short term lease is one with a maximum lease term of 12 months or less and does not include a purchase option the lessee is reasonably certain to exercise.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

§ We will not reassess whether any expired or existing contracts are or contain leases or the lease classification for any existing or expired leases.

§ The impact of adopting ASC 842 will be prospective beginning January 1, 2019. We will not recast prior periods presented in our consolidated financial statements to reflect the new lease accounting guidance.

Based on current information, we expect to recognize at adoption of ASC 842 an estimated $250 million in ROU assets and $250 million in lease liabilities on our consolidated balance sheet at January 1, 2019 based on discounted amounts. These amounts would represent less than 1% of our total consolidated assets and liabilities, respectively.

Fair value measurements
In August 2018, the FASB issued ASU 2018-13, Fair Value Measurements (Topic 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurement, which amends certain disclosure requirements related to fair value measurements. The amendments will require incremental disclosures regarding uncertainties surrounding fair value measurements, including discussions of any interrelationships between significant unobservable inputs used to estimate Level 3 fair value measurements, and changes in unrealized gains and losses. The amendments in this ASU are effective January 1, 2020, which is when we expect to apply the new requirements. We are currently reviewing the effect of this ASU on our consolidated financial statements.

Credit losses
In June 2016, the FASB issued ASU 2016-13, "Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology. These changes are expected to result in the more timely recognition of losses. The amendments in this ASU are effective January 1, 2020, which is when we expect to apply the new requirements to how the allowance for doubtful accounts is determined. We are currently reviewing the effect of this ASU on our consolidated financial statements.

Note 3. Inventories

Our inventory amounts by product type were as follows at the dates indicated:

	December 31,	
	2018	2017
NGLs	$647.7	$917.4
Petrochemicals and refined products	264.7	161.5
Crude oil	593.4	516.3
Natural gas	16.3	14.6
Total	$1,522.1	$1,609.8

In those instances where we take ownership of inventory volumes through percent-of-liquids contracts and similar arrangements (as opposed to outright purchases from third parties for cash), these volumes are valued at market-based prices during the month in which they are acquired.

The following table presents our total cost of sales amounts and lower of cost or net realizable value adjustments for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Cost of sales (1)	$26,789.8	$21,487.0	$15,710.9
Lower of cost or net realizable value adjustments within cost of sales	11.5	9.1	11.5

(1) Cost of sales is a component of “Operating costs and expenses,” as presented on our Statements of Consolidated Operations. Fluctuations in these amounts are primarily due to changes in energy commodity prices and sales volumes associated with our marketing activities.

Due to fluctuating commodity prices, we recognize lower of cost or net realizable value adjustments when the carrying value of our available-for-sale inventories exceeds their net realizable value. These non-cash charges are a component of cost of sales in the period they are recognized. To the extent our commodity hedging strategies address inventory-related price risks and are successful, these inventory valuation adjustments are mitigated or offset. See Note 14 for a description of our commodity hedging activities.

Note 4. Property, Plant and Equipment

The historical costs of our property, plant and equipment and related accumulated depreciation balances were as follows at the dates indicated:

	Estimated Useful Life in Years	December 31, 2018	2017
Plants, pipelines and facilities (1)	3-45 (5)	$42,371.0	$37,132.2
Underground and other storage facilities (2)	5-40 (6)	3,624.2	3,460.9
Transportation equipment (3)	3-10	187.1	177.1
Marine vessels (4)	15-30	828.6	803.8
Land		359.5	273.1
Construction in progress		3,526.8	4,698.1
Total		50,897.2	46,545.2
Less accumulated depreciation		12,159.6	10,924.8
Property, plant and equipment, net		$38,737.6	$35,620.4

(1) Plants, pipelines and facilities include processing plants; NGL, natural gas, crude oil and petrochemical and refined products pipelines; terminal loading and unloading facilities; buildings; office furniture and equipment; laboratory and shop equipment and related assets. We placed a number of growth projects into service since December 31, 2017 including a propane dehydrogenation facility at our Mont Belvieu complex, the first two processing trains at our Orla natural gas processing facility, and a ninth NGL fractionator in Chambers County, Texas at our Mont Belvieu NGL fractionation complex.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(4) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(5) In general, the estimated useful lives of major assets within this category are: processing plants, 20-35 years; pipelines and related equipment, 5-45 years; terminal facilities, 10-35 years; buildings, 20-40 years; office furniture and equipment, 3-20 years; and laboratory and shop equipment, 5-35 years.
(6) In general, the estimated useful lives of assets within this category are: underground storage facilities, 5-35 years; storage tanks, 10-40 years; and water wells, 5-35 years.

In March 2018, we acquired the remaining 50% member interest of our Delaware Processing joint venture, which resulted in the consolidation of $200 million of property, plant and equipment. See Note 12 for information regarding this recent acquisition.

In April 2018, we acquired land in the Houston, Texas area for $85.2 million. The consideration paid consisted of $55.2 million in cash with the balance funded by the issuance of 1,223,242 Enterprise common units.

In October 2018, we sold our Red River System and associated crude oil linefill for $134.9 million and recorded a gain of $20.6 million. The Red River System gathers and transports crude oil from North Texas and southern Oklahoma for delivery to local refineries and pipeline interconnects for further transportation to the Cushing hub and Gulf Coast.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table summarizes our depreciation expense and capitalized interest amounts for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Depreciation expense (1)	$1,436.2	$1,296.1	$1,215.7
Capitalized interest (2)	147.9	192.1	168.2

(1) Depreciation expense is a component of “Costs and expenses” as presented on our Statements of Consolidated Operations.
(2) Capitalized interest is a component of “Interest expense” as presented on our Statements of Consolidated Operations.

Asset Retirement Obligations

We record AROs in connection with legal requirements to perform specified retirement activities under contractual arrangements and/or governmental regulations. Our contractual AROs primarily result from right-of-way agreements associated with our pipeline operations and real estate leases associated with our plant sites. In addition, we record AROs in connection with governmental regulations associated with the abandonment or retirement of above-ground brine storage pits and certain marine vessels. We also record AROs in connection with regulatory requirements associated with the renovation or demolition of certain assets containing hazardous substances such as asbestos. We typically fund our AROs using cash flow from operations.

Property, plant and equipment at December 31, 2018 and 2017 includes $72.5 million and $39.9 million, respectively, of asset retirement costs capitalized as an increase in the associated long-lived asset.

The following table presents information regarding our AROs for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
ARO liability beginning balance	$86.7	$85.4	$58.5
Liabilities incurred	24.4	4.7	4.2
Liabilities settled	(2.5)	(2.2)	(5.7)
Revisions in estimated cash flows	11.5	(6.7)	24.6
Accretion expense	6.2	5.5	3.8
ARO liability ending balance	$126.3	$86.7	$85.4

The following table presents our forecast of ARO-related accretion expense for the years indicated:

2019	2020	2021	2022	2023
$8.1	$8.6	$9.0	$9.6	$10.3

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 5. Investments in Unconsolidated Affiliates

The following table presents our investments in unconsolidated affiliates by business segment at the dates indicated. We account for these investments using the equity method.

	Ownership Interest at December 31, 2018	December 31, 2018	2017
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. ("VESCO")	13.1%	$24.1	$25.7
K/D/S Promix, L.L.C. ("Promix")	50%	28.9	30.9
Baton Rouge Fractionators LLC ("BRF")	32.2%	16.3	17.0
Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu")	50%	35.6	37.0
Texas Express Pipeline LLC ("Texas Express")	35%	337.6	314.4
Texas Express Gathering LLC ("TEG")	45%	43.6	35.9
Front Range Pipeline LLC ("Front Range")	33.3%	175.9	165.7
Delaware Basin Gas Processing LLC ("Delaware Processing") (1)	100%	--	107.3
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC ("Seaway")	50%	1,369.7	1,378.9
Eagle Ford Pipeline LLC ("Eagle Ford Crude Oil Pipeline")	50%	388.7	385.2
Eagle Ford Terminals Corpus Christi LLC ("Eagle Ford Corpus Christi")	50%	109.1	75.1
Natural Gas Pipelines & Services:			
White River Hub, LLC ("White River Hub")	50%	20.1	20.8
Old Ocean Pipeline, LLC ("Old Ocean")	50%	2.7	--
Petrochemical & Refined Products Services:			
Centennial Pipeline LLC ("Centennial")	50%	59.1	60.8
Baton Rouge Propylene Concentrator LLC ("BRPC")	30%	3.2	4.1
Transport 4, LLC ("Transport 4")	25%	0.5	0.6
Total		$2,615.1	$2,659.4

(1) In March 2018, we acquired the remaining 50% membership interest in our Delaware Processing joint venture. See Note 12 for information regarding this acquisition.

NGL Pipelines & Services

The principal business activity of each investee included in our NGL Pipelines & Services segment is described as follows:

§ VESCO owns a natural gas processing facility in south Louisiana and a related gathering system that gathers natural gas from certain offshore developments for delivery to its natural gas processing facility.

§ Promix owns an NGL fractionation facility located in south Louisiana. The facility receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast. In addition, Promix owns an NGL gathering system that gathers mixed NGLs from processing plants in southern Louisiana for its fractionator.

- BRF owns an NGL fractionation facility located in south Louisiana that receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana. In addition, BRF leases an NGL storage cavern.

- Skelly-Belvieu owns a pipeline that 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 Express owns an NGL pipeline that extends from Skellytown to our Mont Belvieu NGL fractionation and storage complex. 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 pipeline also transports mixed NGLs from two gathering systems owned by TEG to Mont Belvieu. In addition, mixed NGLs from the Denver-Julesburg Basin in Colorado are transported to the Texas Express Pipeline using the Front Range Pipeline.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

§ TEG owns two NGL gathering systems that deliver mixed NGLs to the Texas Express Pipeline. The Elk City gathering system 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 gathers mixed NGLs from natural gas processing plants in the Barnett Shale production area in North Texas.

§ Front Range owns an NGL pipeline that transports mixed NGLs from natural gas processing plants located in the Denver-Julesburg Basin to an interconnect with our Texas Express Pipeline and Mid-America Pipeline System and other third party facilities in Skellytown.

Crude Oil Pipelines & Services

The principal business activity of each investee included in our Crude Oil Pipelines & Services segment is described as follows:

§ Seaway owns a pipeline system that 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 on the NYMEX.

The Longhaul System, which consists of two pipelines, provides north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal near Freeport, Texas and a terminal that we own located near Katy, Texas.

The Freeport System consists of a marine import and export dock, three pipelines and other related facilities that transport crude oil to and from Freeport and the Jones Creek terminal. The Texas City System consists of a marine import and export dock, storage tanks, various pipelines and other related facilities that transport crude oil to refineries in the Texas City, Texas area and to and from terminals in the Galena Park area, our Enterprise Crude Houston ("ECHO") terminal and locations along the Houston Ship Channel. The Texas City System also receives production from certain offshore Gulf of Mexico developments.

§ Eagle Ford Crude Oil Pipeline owns a crude oil pipeline that transports crude oil and condensate for producers in South Texas. The system consists of a crude oil and condensate pipeline system originating in Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and extending to Corpus Christi, Texas. The system also includes a pipeline segment that interconnects with our South Texas Crude Oil Pipeline System in Wilson County. This system includes a marine terminal facility in Corpus Christi and storage capacity across the system.

§ Eagle Ford Corpus Christi is a joint venture formed in March 2015 to construct and operate a new deep-water marine crude oil terminal that is designed to handle a variety of ocean-going vessels. The new terminal is expected to be placed into service during the second quarter of 2019.

Natural Gas Pipelines & Services

The principal business activity of each investee included in our Natural Gas Pipelines & Services segment is described as follows:

§ White River Hub owns 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.

§ Old Ocean was formed in May 2018 with Energy Transfer Partners, L.P. ("ETP") to facilitate the resumption of full service on the Old Ocean natural gas pipeline owned by ETP. The 24-inch diameter Old Ocean Pipeline originates in Maypearl, Texas in Ellis County and extends south approximately 240 miles to Sweeny, Texas in Brazoria County. ETP serves as operator of the pipeline.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Petrochemical & Refined Products Services

The principal business activity of each investee included in our Petrochemical & Refined Products Services segment is described as follows:

§ Centennial owns an interstate refined products pipeline that extends from Beaumont, Texas, to Bourbon, Illinois. Centennial also owns a refined products storage terminal located near Creal Springs, Illinois.

§ BRPC owns a propylene fractionation facility located in south Louisiana that fractionates refinery grade propylene into chemical grade propylene.

§ Transport 4 provides pipeline and terminal logistics services used by our refined products pipelines.

Equity Earnings

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
NGL Pipelines & Services	$117.0	$73.4	$61.4
Crude Oil Pipelines & Services	365.4	358.4	311.9
Natural Gas Pipelines & Services	6.8	3.8	3.8
Petrochemical & Refined Products Services (1)	(9.2)	(9.6)	(15.1)
Total	$480.0	$426.0	$362.0

(1) Losses are primarily attributable to our investment in Centennial. As a result of a trend in declining earnings, we estimated the fair value of this equity-method investment during each of the last three fiscal years. Our estimates, based on a combination of market and income approaches, indicate that the fair value of this investment remains in excess of its carrying value.

Excess Cost

On occasion, the price we pay to acquire an ownership interest in a company exceeds the underlying carrying value of the capital accounts we acquire. These excess cost amounts are attributable to the fair value of the underlying tangible assets of these entities exceeding their respective book carrying values at the time of our acquisition of ownership interests in these entities. We amortize such excess cost amounts as a reduction to equity earnings in a manner similar to depreciation. The following table presents our unamortized excess cost amounts by business segment at the dates indicated:

	December 31,	
	2018	2017
NGL Pipelines & Services	$21.7	$22.9

Crude Oil Pipelines & Services	17.4	18.2
Petrochemical & Refined Products Services	1.7	1.8
Total	$40.8	$42.9

In total, amortization of excess cost amounts were $2.1 million for each of the years ended December 31, 2018, 2017 and 2016. We forecast that our amortization of excess cost amount will approximate $2.1 million in each of the next five years.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Summarized Combined Financial Information of Unconsolidated Affiliates

Combined balance sheet information for the last two years and results of operations data for the last three years for our unconsolidated affiliates are summarized in the following table (all data presented on a 100% basis):

	December 31,	
	2018	2017
Balance Sheet Data:		
Current assets	$350.2	$288.8
Property, plant and equipment, net	5,359.1	5,509.7
Other assets	80.4	71.2
Total assets	$5,789.7	$5,869.7
Current liabilities	$220.6	$233.5
Other liabilities	77.9	84.8
Combined equity	5,491.2	5,551.4
Total liabilities and combined equity	$5,789.7	$5,869.7

	For the Year Ended December 31,		
	2018	2017	2016
Income Statement Data:			
Revenues	$1,721.3	$1,509.0	$1,342.0
Operating income	1,074.6	925.9	786.7
Net income	1,069.1	929.5	781.7

Note 6. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets by business segment at the dates indicated:

	December 31, 2018			December 31, 2017		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$457.3	$ (201.9)	$255.4	$447.4	$ (187.5)	$259.9
Contract-based intangibles	363.4	(238.7)	124.7	280.8	(218.4)	62.4
Segment total	820.7	(440.6)	380.1	728.2	(405.9)	322.3
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,203.5	(174.1)	2,029.4	2,203.5	(127.0)	2,076.5
Contract-based intangibles	276.9	(211.7)	65.2	281.0	(171.0)	110.0
Segment total	2,480.4	(385.8)	2,094.6	2,484.5	(298.0)	2,186.5
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(447.8)	902.5	1,350.3	(417.1)	933.2
Contract-based intangibles	464.7	(387.9)	76.8	464.7	(379.5)	85.2

Segment total	1,815.0	(835.7	)	979.3	1,815.0	(796.6	)	1,018.4
Petrochemical & Refined Products Services:								
Customer relationship intangibles	181.4	(51.8	)	129.6	181.4	(45.9	)	135.5
Contract-based intangibles	46.0	(21.2	)	24.8	46.0	(18.4	)	27.6
Segment total	227.4	(73.0	)	154.4	227.4	(64.3	)	163.1
Total intangible assets	$5,343.5	$ (1,735.1	)	$3,608.4	$5,255.1	$ (1,564.8	)	$3,690.3

F-24

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the amortization expense of our intangible assets by business segment for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
NGL Pipelines & Services	$34.7	$28.9	$30.6
Crude Oil Pipelines & Services	87.8	92.5	98.4
Natural Gas Pipelines & Services	39.1	36.2	33.2
Petrochemical & Refined Products Services	8.7	9.3	9.1
Total	$170.3	$166.9	$171.3

The following table presents our forecast of amortization expense associated with existing intangible assets for the years indicated:

2019	2020	2021	2022	2023
$167.1	$159.8	$162.1	$167.6	$167.8

Customer relationship intangible assets

Customer relationship intangible assets represent the estimated economic value assigned to commercial relationships acquired in connection with business combinations. Our customer relationship intangible assets are classified as either (i) basin-specific or (ii) general. Basin-specific customer relationships represent access to customers associated with a defined resource basin (e.g., customers using a natural gas gathering system serving a specific production field) and is analogous to having a franchise in a particular area. General customer relationships are associated with customers whose hydrocarbon volumes are not attributable to specific resource basins (e.g. customers at a marine terminal that handles volumes originating from multiple sources).

The estimated fair value of each customer relationship intangible asset was determined at the time of acquisition using a discounted cash flow analysis, which incorporates various assumptions regarding the acquired business. The assumptions may include Level 3 fair value inputs, including long-range cash flow forecasts that extend for the estimated economic life of the hydrocarbon resource base served by the asset network, anticipated service contract renewals, resource base depletion rates and expected customer attrition rates.

The recognition of customer relationships are supported by a variety of factors. In general, midstream infrastructure requires a significant investment, both in terms of initial construction costs and ongoing maintenance, and is generally supported by long-term contracts that establish a customer base. The level of expenditures and regulatory requirements involved in constructing new midstream asset networks can create significant economic barriers to entry that may limit potential competition. Furthermore, efficient, continuous operation of the acquired fixed assets not only supports the commercial relationships existing at the time of the acquisition, but it provides us with opportunities to establish new ones. These factors support the long-term value attributed to our customer relationship intangible assets.

With respect to amortization periods, the duration of a basin-specific customer relationship is limited to the estimated economic life of the associated resource basin. The duration of our other customer relationships is typically limited to the term of the underlying service contracts, including assumed renewals. Amortization expense attributable to customer relationships is recorded in a manner that closely resembles the pattern in which we expect to benefit from such relationships.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

At December 31, 2018, the carrying value of our portfolio of customer relationship intangible assets was $3.3 billion, the principal components of which were as follows:

	Weighted Average Remaining Amortization Period	December 31, 2018		
		Gross Value	Accumulated Amortization	Carrying Value
Basin-specific customer relationships:				
EFS Midstream	23.4 years	$1,409.8	$ (117.0)	$1,292.8
State Line and Fairplay	28.2 years	895.0	(183.2)	711.8
San Juan Gathering	20.8 years	331.3	(227.7)	103.6
Encinal	8.0 years	132.9	(103.5)	29.4
General customer relationships:				
Oiltanking	25.0 years	1,192.5	(86.1)	1,106.4

- § The EFS Midstream customer relationships provide us with long-term access to natural gas, NGL and condensate producers served by our EFS Midstream System, which we acquired in 2015. The EFS Midstream System serves producers in the Eagle Ford Shale, providing condensate gathering and processing services as well as gathering, treating and compression services for associated natural gas.

- § The State Line and Fairplay customer relationships provide us with long-term access to natural gas producers served by our Haynesville and Fairplay Gathering Systems, which we acquired in 2010. The Haynesville Gathering System gathers and treats 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 Cotton Valley formation within Panola and Rusk Counties in East Texas for delivery to regional markets.

- § The San Juan Gathering customer relationships provide us with long-term access to natural gas producers served by our San Juan Gathering System, which we acquired in 2004. The San Juan Gathering System gathers and treats natural gas produced from the San Juan Basin in northern New Mexico and southern Colorado and delivers the natural gas either directly into interstate pipelines (if dry natural gas) or to regional natural gas plants, including our Chaco facility, for further processing (if rich natural gas) prior to being transported on interstate pipelines.

- § The Encinal customer relationships provide us with long-term access to natural gas producers in the Olmos and Wilcox formations in South Texas. We acquired this intangible asset in 2006.

- § The Oiltanking customer relationships provide us with long-term access to crude oil and refined products storage and terminal customers served at our Houston Ship Channel and Beaumont, Texas terminals. We acquired this intangible asset in 2014.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Contract-based intangible assets
Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations. These intangible assets are typically valued using an income approach that incorporate the terms of the agreements. At December 31, 2018, the carrying value of our portfolio of contract-based intangible assets was $291.5 million, the principal components of which were as follows:

	Weighted Average Remaining Amortization Period	December 31, 2018		
		Gross Value	Accumulated Amortization	Carrying Value
Oiltanking customer contracts	4.0 years	$293.3	$ (221.1)	$ 72.2
Jonah natural gas gathering agreements	23.0 years	224.4	(166.3)	58.1
Delaware Basin natural gas processing contracts	8.0 years	82.6	(6.4)	76.2

§ The Oiltanking customer contracts represent the estimated value we assigned to crude oil storage and terminal agreements we acquired in 2014 associated with our Houston and Beaumont terminals. Amortization expense attributable to these contracts is recorded using a straight-line approach over the terms of the underlying contracts.

§ The Jonah natural gas gathering agreements represent the estimated value we assigned to natural gas gathering contracts acquired in 2001 associated with the Jonah Gathering System. Amortization expense attributable to these intangible assets is recorded using a units-of-production method based on gathering volumes.

§ The Delaware Basin natural gas processing contracts represent the estimated value we assigned to natural gas processing contracts we acquired in 2018 in connection with our step acquisition of the remaining 50% member interest in Delaware Processing (see Note 12). Amortization expense attributable to these contracts is recorded using a straight-line approach over the terms of the underlying contracts.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing at the end of each fiscal year, and more frequently, if circumstances indicate it is probable that the fair value of goodwill is below its carrying amount. We did not record any goodwill impairment charges, or reclassify any goodwill amounts between business segments, during the years ended December 31, 2018, 2017 or 2016. Based on our most recent goodwill impairment test at December 31, 2018, we estimated that the fair value of each of our reporting units was substantially in excess of its carrying value (i.e., by at least 10%). See Note 10 for our goodwill by segment balances.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7. Debt Obligations

The following table presents our consolidated debt obligations (arranged by company and maturity date) at the dates indicated:

	December 31, 2018	2017
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$--	$1,755.7
Senior Notes V, 6.65% fixed-rate, due April 2018	--	349.7
Senior Notes OO, 1.65% fixed-rate, due May 2018	--	750.0
Senior Notes N, 6.50% fixed-rate, due January 2019	700.0	700.0
364-Day Revolving Credit Agreement, variable-rate, due September 2019	--	--
Senior Notes LL, 2.55% fixed-rate, due October 2019	800.0	800.0
Senior Notes Q, 5.25% fixed-rate, due January 2020	500.0	500.0
Senior Notes Y, 5.20% fixed-rate, due September 2020	1,000.0	1,000.0
Senior Notes TT, 2.80% fixed-rate, due February 2021	750.0	--
Senior Notes RR, 2.85% fixed-rate, due April 2021	575.0	575.0
Senior Notes VV, 3.50% fixed-rate, due February 2022	750.0	--
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
Multi-Year Revolving Credit Facility, variable-rate, due September 2022	--	--
Senior Notes HH, 3.35% fixed-rate, due March 2023	1,250.0	1,250.0
Senior Notes JJ, 3.90% fixed-rate, due February 2024	850.0	850.0
Senior Notes MM, 3.75% fixed-rate, due February 2025	1,150.0	1,150.0
Senior Notes PP, 3.70% fixed-rate, due February 2026	875.0	875.0
Senior Notes SS, 3.95% fixed-rate, due February 2027	575.0	575.0
Senior Notes WW, 4.15% fixed-rate, due October 2028	1,000.0	--
Senior Notes D, 6.875% fixed-rate, due March 2033	500.0	500.0
Senior Notes H, 6.65% fixed-rate, due October 2034	350.0	350.0
Senior Notes J, 5.75% fixed-rate, due March 2035	250.0	250.0
Senior Notes W, 7.55% fixed-rate, due April 2038	399.6	399.6
Senior Notes R, 6.125% fixed-rate, due October 2039	600.0	600.0
Senior Notes Z, 6.45% fixed-rate, due September 2040	600.0	600.0
Senior Notes BB, 5.95% fixed-rate, due February 2041	750.0	750.0
Senior Notes DD, 5.70% fixed-rate, due February 2042	600.0	600.0
Senior Notes EE, 4.85% fixed-rate, due August 2042	750.0	750.0
Senior Notes GG, 4.45% fixed-rate, due February 2043	1,100.0	1,100.0
Senior Notes II, 4.85% fixed-rate, due March 2044	1,400.0	1,400.0
Senior Notes KK, 5.10% fixed-rate, due February 2045	1,150.0	1,150.0
Senior Notes QQ, 4.90% fixed-rate, due May 2046	975.0	975.0
Senior Notes UU, 4.25% fixed-rate, due February 2048	1,250.0	--
Senior Notes XX, 4.80% fixed-rate, due February 2049	1,250.0	--
Senior Notes NN, 4.95% fixed-rate, due October 2054	400.0	400.0
TEPPCO senior debt obligations:		
TEPPCO Senior Notes, 6.65% fixed-rate, due April 2018	--	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	23,750.0	21,605.7

EPO Junior Subordinated Notes A, variable-rate, redeemed August 2018	--	521.1
EPO Junior Subordinated Notes B, fixed/variable-rate, redeemed March 2018	--	682.7
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (1)	256.4	256.4
EPO Junior Subordinated Notes D, fixed/variable-rate, due August 2077 (2)	700.0	700.0
EPO Junior Subordinated Notes E, fixed/variable-rate, due August 2077 (3)	1,000.0	1,000.0
EPO Junior Subordinated Notes F, fixed/variable-rate, due February 2078 (4)	700.0	--
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	26,420.6	24,780.1
Other, non-principal amounts	(242.4)	(211.4)
Less current maturities of debt	(1,500.1)	(2,855.0)
Total long-term debt	$$ 24,678.1	$$ 21,713.7

(1) Variable rate is reset quarterly and based on 3-month LIBOR plus 2.778%.
(2) Fixed rate of 4.875% through August 15, 2022; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.986%.
(3) Fixed rate of 5.250% through August 15, 2027; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 3.033%.
(4) Fixed rate of 5.375% through February 14, 2028; thereafter, a variable rate reset quarterly and based on 3-month LIBOR plus 2.57%.

References in this footnote to “TEPPCO” mean TEPPCO Partners, L.P. prior to its merger with one of our wholly owned subsidiaries in October 2009.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Information Regarding Variable Interest Rates Paid

The following table presents the range of interest rates and weighted-average interest rates paid on our consolidated variable-rate debt during the year ended December 31, 2018:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	1.50% to 2.50%	2.24%
Multi-Year Revolving Credit Facility	2.58% to 5.00%	3.37%
EPO Junior Subordinated Notes A (prior to redemption)	5.08% to 6.07%	5.71%
EPO Junior Subordinated Notes B (prior to redemption)	7.03%	7.03%
EPO Junior Subordinated Notes C	4.26% to 5.52%	4.91%

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at December 31, 2018 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	2019	2020	2021	2022	2023	Thereafter
Senior Notes	$23,750.0	$1,500.0	$1,500.0	$1,325.0	$1,400.0	$1,250.0	$16,775.0
Junior Subordinated Notes	2,670.6	--	--	--	--	--	2,670.6
Total	$26,420.6	$1,500.0	$1,500.0	$1,325.0	$1,400.0	$1,250.0	$19,445.6

Parent-Subsidiary Guarantor Relationships

Enterprise Products Partners L.P. acts as guarantor of the consolidated debt obligations of EPO, with the exception of the remaining debt obligations of TEPPCO. If EPO were to default on any of its guaranteed debt, Enterprise Products Partners L.P. would be responsible for full and unconditional repayment of that obligation.

EPO Debt Obligations

Commercial Paper Notes
In June 2018, EPO increased the aggregate principal amount of short-term notes that it could issue (and have outstanding at any time) under its commercial paper program from $2.5 billion to $3.0 billion. As a back-stop to the program, we intend to maintain a minimum available borrowing capacity under EPO’s Multi-Year Revolving Credit Facility equal to the aggregate amount outstanding under our commercial paper notes. All commercial paper notes issued under the program are senior unsecured obligations of EPO that are unconditionally guaranteed by Enterprise Products Partners L.P.

364-Day Credit Agreement
In September 2018, EPO entered into a 364-Day Revolving Credit Agreement that replaced its prior 364-day credit facility. The new 364-Day Revolving Credit Agreement matures in September 2019. There are currently no principal amounts outstanding under this revolving credit agreement.

Under the terms of the new 364-Day Revolving Credit Agreement, EPO may borrow up to $2.0 billion (which may be increased by up to $200 million to $2.2 billion at EPO’s election, provided certain conditions are met) at a variable interest rate for a term of up to 364 days, subject to the terms and conditions set forth therein. To the extent that principal amounts are outstanding at the maturity date, EPO may elect to have the entire principal balance then outstanding continued as a non-revolving term loan for a period of one additional year, payable in September 2020. Borrowings under this revolving credit agreement may be used for working capital, capital expenditures, acquisitions and general company purposes.

The new 364-Day Revolving Credit Agreement contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of any amounts borrowed under this credit agreement. The credit agreement also restricts EPO's ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if an event of default (as defined in the credit agreement) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

EPO's obligations under the new 364-Day Revolving Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P.

Multi-Year Revolving Credit Facility

In September 2017, EPO entered into a revolving credit agreement that matures in September 2022 (the "Multi-Year Revolving Credit Facility"). This new facility replaced EPO's prior multi-year revolving credit facility that was scheduled to mature in September 2020. There are currently no principal amounts outstanding under the new credit facility.

Under the terms of the new Multi-Year Revolving Credit Facility, EPO may borrow up to $4.0 billion (which may be increased by up to $500 million to $4.5 billion at EPO's election, provided certain conditions are met) at a variable interest rate for a term of five years, subject to the terms and conditions set forth therein. Borrowings under this revolving credit facility may be used as a backstop for commercial paper and for working capital, capital expenditures, acquisitions and general company purposes.

The Multi-Year Revolving Credit Facility contains customary representations, warranties, covenants (affirmative and negative) and events of default, the occurrence of which would permit the lenders to accelerate the maturity date of any amounts borrowed under this credit facility. The credit facility also restricts EPO's ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if an event of default (as defined in the credit facility) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

EPO's obligations under the Multi-Year Revolving Credit Facility are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P.

Senior Notes

EPO's fixed-rate senior notes are unsecured obligations of EPO that rank equal with its existing and future unsecured and unsubordinated indebtedness. They are senior to any existing and future subordinated indebtedness of EPO. EPO's senior notes are subject to make-whole redemption rights and were issued under indentures containing certain covenants, which generally restrict its ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions. In total, EPO issued $5.0 billion and $1.25 billion of senior notes during the years ended December 31, 2018 and 2016, respectively.

In February 2018, EPO issued $2.0 billion aggregate principal amount of senior notes comprised of (i) $750 million principal amount of senior notes due February 2021 ("Senior Notes TT") and (ii) $1.25 billion principal amount of senior notes due February 2048 ("Senior Notes UU").

Net proceeds from the February 2018 senior notes offerings, together with the net proceeds from the February 2018 offering of Junior Subordinated Notes F (described below), were used by EPO for the temporary repayment of amounts outstanding under its commercial paper program, general company purposes, and the redemption of all $682.7 million outstanding aggregate principal amount of its Junior Subordinated Notes B.

Senior Notes TT were issued at 99.946% of their principal amount and have a fixed-rate interest rate of 2.80% per year. Senior Notes UU were issued at 99.865% of their principal amount and have a fixed-rate interest rate of 4.25% per year. Enterprise Products Partners L.P. has guaranteed the senior notes through an unconditional guarantee on an unsecured and unsubordinated basis.

In October 2018, EPO issued $3.0 billion aggregate principal amount of senior notes comprised of (i) $750 million principal amount of senior notes due February 2022 (“Senior Notes VV”), (ii) $1.00 billion principal amount of senior notes due October 2028 (“Senior Notes WW”) and (iii) $1.25 billion principal amount of senior notes due February 2049 (“Senior Notes XX”). Net proceeds from this offering were used by EPO for the temporary repayment of amounts outstanding under its commercial paper program and for general company purposes, including for growth capital expenditures.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Senior Notes VV were issued at 99.985% of their principal amount and have a fixed-rate interest rate of 3.50% per year. Senior Notes WW were issued at 99.764% of their principal amount and have a fixed-rate interest rate of 4.15% per year. Senior Notes XX were issued at 99.390% of their principal amount and have a fixed-rate interest rate of 4.80% per year. Enterprise Products Partners L.P. has guaranteed the senior notes through an unconditional guarantee on an unsecured and unsubordinated basis.

EPO Junior Subordinated Notes
EPO's payment obligations under its junior notes are subordinated to all of its current and future senior indebtedness (as defined in the related indenture agreement). Enterprise Products Partners L.P. guarantees repayment of amounts due under these junior notes through an unsecured and subordinated guarantee. The indenture agreement governing these notes allows EPO to defer interest payments on one or more occasions for up to ten consecutive years subject to certain conditions. Subject to certain exceptions, during any period in which interest payments are deferred, neither we nor EPO can declare or make any distributions on any of our respective equity securities or make any payments on indebtedness or other obligations that rank equal with or are subordinate to our junior notes. Each series of our junior notes rank equal with each other. Generally, each series of junior notes are not redeemable by EPO while such notes bear interest at a fixed annual rate. In total, EPO issued $700.0 million and $1.7 billion of junior notes during the years ended December 31, 2018 and 2017, respectively.

In connection with the issuance of EPO's Junior Subordinated Notes A, Junior Subordinated Notes B and Junior Subordinated Notes C, EPO entered into separate Replacement Capital Covenants in favor of covered debt holders (as defined in the underlying documents) pursuant to which EPO agreed, for the benefit of such debt holders, that it would not redeem or repurchase such junior notes unless such redemption or repurchase is made using proceeds from the issuance of certain securities.

In February 2018, EPO issued $700 million in principal amount of junior subordinated notes. The Junior Subordinated Notes F are redeemable at EPO's option, in whole or in part, on one or more occasions, on or after February 15, 2028 at 100% of their principal amount, plus any accrued and unpaid interest thereon, and bear interest at a fixed rate of 5.375% per year through February 14, 2028. Beginning February 15, 2028, the Junior Subordinated Notes F will bear interest at a floating rate based on a three-month LIBOR rate plus 2.57%, reset quarterly. Enterprise Products Partners L.P. has guaranteed the Junior Subordinated Notes F through an unconditional guarantee on an unsecured and subordinated basis.

In March 2018, EPO redeemed all of the $682.7 million outstanding aggregate principal amount of its Junior Subordinated Notes B at a price equal to 100% of the principal amount of the notes being redeemed, plus all accrued and unpaid interest thereon to, but not including, the redemption date. This redemption was funded by EPO's issuance of senior notes and junior subordinated notes in February 2018.

In August 2018, EPO redeemed all of the $521.1 million outstanding aggregate principal amount of its Junior Subordinated Notes A at a price equal to 100% of the principal amount of the notes being redeemed, plus all accrued and unpaid interest thereon to, but not including, the redemption date. This redemption was funded by the issuance of short-term notes under EPO's commercial paper program.

Letters of Credit

At December 31, 2018, EPO had $101.4 million of letters of credit outstanding primarily related to our commodity hedging activities.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at December 31, 2018.
F-31

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 8. Equity and Distributions

Partners Equity

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units) outstanding. The following table summarizes changes in the number of our outstanding units since January 1, 2016:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at January 1, 2016	2,010,592,504	1,960,520	2,012,553,024
Common units issued in connection with ATM program	87,867,037	--	87,867,037
Common units issued in connection with DRIP and EUPP	16,316,534	--	16,316,534
Common units issued in connection with the vesting of phantom unit awards	1,761,455	--	1,761,455
Common units issued in connection with the vesting of restricted common unit awards	1,234,502	(1,234,502)	--
Forfeiture of restricted common unit awards	--	(43,724)	(43,724)
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(1,000,619)	--	(1,000,619)
Other	134,707	--	134,707
Number of units outstanding at December 31, 2016	2,116,906,120	682,294	2,117,588,414
Common units issued in connection with ATM program	21,807,726	--	21,807,726
Common units issued in connection with DRIP and EUPP	19,046,019	--	19,046,019
Common units issued in connection with the vesting of phantom unit awards	2,485,580	--	2,485,580
Common units issued in connection with the vesting of restricted common unit awards	681,044	(681,044)	--
Forfeiture of restricted common unit awards	--	(1,250)	(1,250)
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(1,027,798)	--	(1,027,798)
Common units issued in connection with employee compensation	1,176,103	--	1,176,103
Other	14,685	--	14,685
Number of units outstanding at December 31, 2017	2,161,089,479	--	2,161,089,479
Common units issued in connection with DRIP and EUPP	19,861,951	--	19,861,951
Common units issued in connection with the vesting of phantom unit awards	3,479,958	--	3,479,958
Cancellation of treasury units acquired in connection with the vesting of equity-based awards	(1,037,522)	--	(1,037,522)
Common units issued in connection with employee compensation	1,443,586	--	1,443,586
Common units issued in connection with land acquisition (see Note 4)	1,223,242	--	1,223,242
Cancellation of treasury units acquired in connection with buyback program	(1,236,800)	--	(1,236,800)

Other	45,135	--	45,135
Number of units outstanding at December 31, 2018	2,184,869,029	--	2,184,869,029

Our common units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our Sixth Amended and Restated Agreement of Limited Partnership (as amended from time to time, the "Partnership Agreement"). We are managed by our general partner, Enterprise GP.

In accordance with our Partnership Agreement, capital accounts are maintained for our limited partners. The capital account provisions of our Partnership Agreement incorporate principles established for U.S. federal income tax purposes and are not comparable to the equity amounts presented in our consolidated financial statements prepared in accordance with GAAP. Earnings and cash distributions are allocated to holders of our common units in accordance with their respective percentage interests.

The net cash proceeds we received from the issuance of common units during the year ended December 31, 2018 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facilities and for general partnership purposes.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Universal shelf registration statement
We have a universal shelf registration statement (the "2016 Shelf") on file with the SEC which allows Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. EPO issued $5.7 billion aggregate principal amount of senior notes and junior subordinated notes using the 2016 Shelf during the year ended December 31, 2018 (see Note 7). In addition, EPO issued (i) $1.7 billion of junior subordinated notes using the 2016 Shelf during the year ended December 31, 2017 and (ii) $1.25 billion of senior notes using a similar prior universal shelf registration statement during the year ended December 31, 2016. The 2016 Shelf will expire in May 2019, and we expect to file a replacement universal shelf registration statement at or before such time. We may issue additional equity and debt securities in the future to assist us in meeting our funding and liquidity requirements, including those related to capital investments.

At-the-Market ("ATM") Program
In November 2017, we filed an amended registration statement with the SEC covering the issuance of up to $2.54 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings in connection with our ATM program. Pursuant to this program, we may sell common units under an equity distribution agreement between Enterprise Products Partners L.P. and certain broker-dealers from time-to-time by means of ordinary brokers' transactions through the NYSE at market prices, in block transactions or as otherwise agreed to with the broker-dealer parties to the agreement.

We did not issue any common units under the ATM program in 2018. During 2017, we issued 21,807,726 common units under the ATM program for aggregate gross cash proceeds of $603.1 million, resulting in total net cash proceeds of $597.0 million. During 2016, we issued 87,867,037 common units under the ATM program for aggregate gross cash proceeds of $2.17 billion, resulting in total net cash proceeds of $2.16 billion. This includes 3,830,256 common units sold in January 2016 to privately held affiliates of EPCO, which generated gross proceeds of $100 million.

After taking into account the aggregate sales price of common units sold under the ATM program through December 31, 2018, we have the capacity to issue additional common units under the ATM program up to an aggregate sales price of $2.54 billion.

Distribution reinvestment plan
We have a registration statement on file with the SEC in connection with our distribution reinvestment plan ("DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of our common units they own by reinvesting the quarterly cash distributions they receive from us into the purchase of additional common units at a discount ranging from 0% to 5%. Beginning with the distribution declared with respect to the fourth quarter of 2017 and paid in February 2018, the discount was reduced from 5% to 2.5%. Likewise, beginning with the distribution declared with respect to the fourth quarter of 2018 and paid in February 2019, the discount was reduced from 2.5% to 0%. We have the sole discretion to determine whether common units purchased under the DRIP will come from our authorized but unissued common units or from common units purchased on the open market by the DRIP administrator.

Activity under our DRIP for the last three years was as follows: 19,316,781 new common units issued during 2018, which generated net cash proceeds of $523.3 million; 18,541,355 new common units issued during 2017, which generated net cash proceeds of $462.9 million; and 15,809,503 new common units issued during 2016, which generated net cash proceeds of $374.0 million. Privately held affiliates of EPCO reinvested $213 million, $100 million and $100 million through the DRIP in each of the years ended December 31, 2018, 2017 and 2016, respectively (this amount being a component of the net cash proceeds presented for each period).

After taking into account the number of common units issued under the DRIP through December 31, 2018, we have the capacity to deliver an additional 61,400,359 common units under this plan.

Employee unit purchase plan

In addition to the DRIP, we have registration statements on file with the SEC in connection with our employee unit purchase plan ("EUPP"). Activity under our EUPP for the last three years was as follows: 545,170 new common units issued during 2018, which generated net cash proceeds of $15.1 million; 504,664 new common units issued during 2017, which generated net cash proceeds of $13.5 million; and 507,031 new common units issued during 2016, which generated net cash proceeds of $12.7 million.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

After taking into account the number of common units issued under the EUPP through December 31, 2018, we have the capacity to deliver an additional 5,215,641 common units under this plan.

Registration Rights Agreement with Oiltanking Holding Americas, Inc. ("OTA")
In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking Partners, L.P. ("Oiltanking"), all of the member interests of OTLP GP, LLC, the general partner of Oiltanking ("Oiltanking GP"), and the incentive distribution rights ("IDRs") held by Oiltanking GP from OTA, a U.S. corporation, as the first step of a two-step acquisition of Oiltanking. In February 2015, we completed the second step of this transaction consisting of the acquisition of the noncontrolling interests in Oiltanking.

In order to fund the equity consideration paid in Step 1 of the Oiltanking acquisition, 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, 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, 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.

Common units issued in connection with employee compensation
In February 2018 and 2017, certain employees of EPCO received discretionary bonus payments, less any retirement plan deductions and applicable withholding taxes, for work performed on our behalf during the prior fiscal year (e.g., the February 2018 bonus amount was with respect to the year ended December 31, 2017). The net dollar value of the bonus amounts was remitted to employees through the issuance of an equivalent value of newly issued Enterprise common units under EPCO's 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). In February 2018, we issued 1,443,586 common units, which had a value of $39.1 million, in connection with the employee bonus awards. In February 2017, we issued 1,176,103 common units, which had a value of $33.7 million. The compensation expense associated with each bonus award was recognized during the year in which the work was performed. See Note 13 for additional information regarding the 2008 Plan.

Treasury Units
In December 1998, we announced a common unit buyback, or repurchase, program whereby we, together with certain affiliates, could repurchase up to 4,000,000 of our common units on the open market. We purchased the remaining authorized amount of 1,236,800 common units in late December 2018 for $30.8 million at an average price of $24.92 per unit.

During the year ended December 31, 2018, a total of 3,479,958 phantom units vested and 1,037,522 units were sold back to us by employees to cover withholding tax requirements related to the vesting of phantom unit awards. The total cost of these treasury unit purchases was $27.3 million. We cancelled such treasury units immediately upon acquisition. See Note 13 for additional information regarding our equity-based awards.

See Note 22 for subsequent event information regarding the establishment of a $2.0 billion unit buyback program in January 2019.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) primarily reflects cumulative gain or loss on derivative instruments designated and qualified as cash flow hedges from inception less gains or losses previously reclassified from accumulated other comprehensive income (loss) into earnings. Gain or loss amounts related to cash flow hedges recorded in accumulated other comprehensive income (loss) are reclassified to earnings in the same period(s) in which the underlying hedged forecasted transactions affect earnings. If it becomes probable that a forecasted transaction will not occur, the related net gain or loss in accumulated other comprehensive income (loss) is immediately reclassified into earnings.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables present the components of accumulated other comprehensive income (loss) as reported on our Consolidated Balance Sheets at the dates indicated:

	Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Accumulated Other Comprehensive Income (Loss), January 1, 2017	$(83.8)	$(199.8)	$3.6	$(280.0)
Other comprehensive income (loss) for period, before reclassifications	(38.5)	(5.7)	(0.1)	(44.3)
Reclassification of losses (gains) to net income during period	112.2	40.4	--	152.6
Total other comprehensive income (loss) for period	73.7	34.7	(0.1)	108.3
Accumulated Other Comprehensive Income (Loss), December 31, 2017	(10.1)	(165.1)	3.5	(171.7)
Other comprehensive income (loss) for period, before reclassifications	293.2	22.2	(0.5)	314.9
Reclassification of losses (gains) to net income during period	(130.4)	38.1	--	(92.3)
Total other comprehensive income (loss) for period	162.8	60.3	(0.5)	222.6
Accumulated Other Comprehensive Income (Loss), December 31, 2018	$152.7	$(104.8)	$3.0	$50.9

The following table presents reclassifications of (income) loss out of accumulated other comprehensive income (loss) into net income during the years indicated:

		For the Year Ended December 31,	
	Location	2018	2017
Losses (gains) on cash flow hedges:			
Interest rate derivatives	Interest expense	$38.1	$40.4
Commodity derivatives	Revenue	(131.7)	111.6
Commodity derivatives	Operating costs and expenses	1.3	0.6
Total		$(92.3)	$152.6

Noncontrolling Interests

Noncontrolling interests represent third party ownership interests in our consolidated subsidiaries.

Enterprise Navigator Ethylene Terminal LLC
In January 2018, we formed a new business venture with Navigator Ethylene Terminals LLC (“Navigator”) to construct and own an ethylene export terminal, which is located at Morgan’s Point on the Houston Ship Channel. Navigator holds a noncontrolling 50% equity interest in Enterprise Navigator Ethylene Terminal LLC, which owns the export facility.

Whitethorn Pipeline Company LLC
In June 2018, an affiliate of Western Gas Partners, LP (“Western”) acquired a noncontrolling 20% equity interest in our subsidiary, Whitethorn Pipeline Company LLC (“Whitethorn”), for $189.6 million in cash. This amount is a component of contributions from noncontrolling interests as presented on our Statement of Consolidated Cash Flows for the year ended December 31, 2018. Whitethorn owns the majority of our Midland-to-ECHO 1 Pipeline System.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Cash Distributions

The following table presents Enterprise's declared quarterly cash distribution rates per common unit with respect to the quarter indicated. Actual cash distributions are paid by Enterprise within 45 days after the end of each fiscal quarter.

	Distribution Per Common Unit	Record Date	Payment Date
2016:			
1st Quarter	$ 0.3950	4/29/2016	5/6/2016
2nd Quarter	$ 0.4000	7/29/2016	8/5/2016
3rd Quarter	$ 0.4050	10/31/2016	11/7/2016
4th Quarter	$ 0.4100	1/31/2017	2/7/2017
2017:			
1st Quarter	$ 0.4150	4/28/2017	5/8/2017
2nd Quarter	$ 0.4200	7/31/2017	8/7/2017
3rd Quarter	$ 0.4225	10/31/2017	11/7/2017
4th Quarter	$ 0.4250	1/31/2018	2/7/2018
2018:			
1st Quarter	$ 0.4275	4/30/2018	5/8/2018
2nd Quarter	$ 0.4300	7/31/2018	8/8/2018
3rd Quarter	$ 0.4325	10/31/2018	11/8/2018
4th Quarter	$ 0.4350	1/31/2019	2/8/2019

In January 2019, based on current expectations, management announced its plans to continue to recommend to the Board an increase of $0.0025 per unit per quarter to our cash distribution rate with respect to 2019. The anticipated rate of increase would result in distributions for 2019 (of $1.7650 per unit) being 2.3% higher than those paid for 2018 (of $1.7250 per unit). The payment of any quarterly cash distribution is subject to Board approval and management's evaluation of our financial condition, results of operations and cash flows in connection with such payment.

Shin Oak NGL Pipeline Option

In May 2018, we granted Apache Corporation ("Apache") an option to acquire up to a 33% equity interest in our subsidiary that owns the Shin Oak NGL Pipeline, which entered limited commercial service in February 2019. In November 2018, Apache contributed the Shin Oak option to Altus Midstream Company ("Altus"), which is majority-owned by Apache. The option is exercisable within sixty days after certain completion milestones are met (as defined in the underlying agreements), which we expect to occur in the second quarter of 2019.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 9. Revenues

We classify our revenues into sales of products and midstream services. Product sales relate primarily to our various marketing activities whereas midstream services represent our other integrated businesses (i.e., processing, fractionation, transportation, storage and terminaling). The following table presents our revenues by business segment, and further by revenue type, for the years indicated:

	For the Year Ended December 31,		
	2018 (1)	2017 (2)	2016 (2)
NGL Pipelines & Services:			
Sales of NGLs and related products	$12,920.9	$10,521.3	$8,380.5
Segment midstream services:			
Natural gas processing and fractionation	1,341.0	719.1	714.6
Transportation	1,007.0	891.7	885.6
Storage and terminals	380.0	335.9	261.8
Total segment midstream services	2,728.0	1,946.7	1,862.0
Total NGL Pipelines & Services	15,648.9	12,468.0	10,242.5
Crude Oil Pipelines & Services:			
Sales of crude oil	10,001.2	7,365.2	5,802.5
Segment midstream services:			
Transportation	676.5	473.9	411.1
Storage and terminals	364.9	317.7	301.4
Total segment midstream services	1,041.4	791.6	712.5
Total Crude Oil Pipelines & Services	11,042.6	8,156.8	6,515.0
Natural Gas Pipelines & Services:			
Sales of natural gas	2,411.7	2,238.5	1,591.9
Segment midstream services:			
Transportation	1,042.7	907.1	951.1
Total segment midstream services	1,042.7	907.1	951.1
Total Natural Gas Pipelines & Services	3,454.4	3,145.6	2,543.0
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	5,535.4	4,696.3	2,921.9
Segment midstream services:			
Fractionation and isomerization	188.3	156.3	142.6
Transportation, including marine logistics	481.8	430.7	456.2
Storage and terminals	182.8	187.8	201.1
Total segment midstream services	852.9	774.8	799.9
Total Petrochemical & Refined Products Services	6,388.3	5,471.1	3,721.8
Total consolidated revenues	$36,534.2	$29,241.5	$23,022.3

(1) Revenues are accounted for under ASC 606 upon implementation at January 1, 2018.
(2) Revenues are accounted for under ASC 605 for historical periods prior to January 1, 2018.

Substantially all of our revenues are derived from contracts with customers as defined within ASC 606. In total, product sales and midstream services accounted for 84% and 16%, respectively, of our consolidated revenues for the year ended December 31, 2018. During the year ended December 31, 2017, product sales and midstream services accounted for 85% and 15%, respectively, of our consolidated revenues. During the year ended December 31, 2016, product sales and midstream services accounted for 81% and 19%, respectively, of our consolidated revenues.

Apart from the following information regarding natural gas processing, we did not have any significant changes in connection with the adoption of ASC 606.

§ Natural gas processing utilizes service contracts that are either fee-based, commodity-based or a combination of the two. Our commodity-based contracts include keepwhole, margin-band, percent-of-liquids, percent-of-proceeds and contracts featuring a combination of commodity and fee-based terms. When a cash fee for natural gas processing services is stipulated by a contract, we record revenue as a producer’s natural gas has been processed.

F-37

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Under ASC 605, our natural gas processing business did not recognize revenue in connection with non-cash consideration (the "equity NGL volumes") it received under percent-of-liquids and similar arrangements. We recognized revenue when the associated NGLs were delivered and sold to downstream customers under NGL marketing product sales contracts.

Under ASC 606, our natural gas processing business recognizes the value of the equity NGL volumes it receives from customers as a form of midstream service revenue. The value assigned to this non-cash consideration and related inventory is based on the market value of the equity NGLs we are entitled to when the services are performed. We also recognize revenue, along with a corresponding cost of sales, when the NGLs are delivered and sold to downstream customers under NGL marketing product sales contracts.

The additional service revenue recognized for the non-cash consideration increased our total revenues by approximately 2% for the year ended December 31, 2018 when compared to the amount of revenues we would have recognized under ASC 605 for the year. Due to the rapid turnover of our inventories of NGL products each month, there was no significant change in our gross operating margin from natural gas processing and related NGL marketing activities as a result of the changes required by ASC 606.

The following information describes the nature of our significant revenue streams by segment and type:

NGL Pipelines & Services

Sales of NGLs and related products
NGL marketing activities generate revenues from merchant activities such as spot and term sales of NGLs and related products that we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and long-term contract purchases. Revenue from these sales contracts is recognized when the NGLs are sold and delivered to customers at market-based prices.

Midstream services
Natural gas processing utilizes 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. Our commodity-based contracts include keepwhole, margin-band, percent-of-liquids, percent-of-proceeds and contracts featuring a combination of commodity and fee-based terms. We recognize revenues related to the equity NGLs we receive under commodity-based contracts (once the processing service has been performed and we are entitled to such volumes) at market value.

NGL pipeline transportation contracts and tariffs typically generate revenue based on a fixed fee per gallon of liquids multiplied by the volume transported and delivered (or capacity reserved). Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Under certain agreements customers are required to ship a minimum volume with a provision that allows the shipper to make-up any volume shortfalls over an agreed-upon period (referred to as "make-up rights"). Revenue pursuant to such agreements is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the likelihood of the shipper's ability to meet the minimum volume commitment becomes remote, or when the pipeline is otherwise released from its performance obligation.

NGL fractionation primarily generates revenue under fee-based arrangements. These fees are contractually subject to adjustment for changes in certain fractionation expenses (e.g., natural gas fuel costs) and are recognized in the period services are provided.

NGL and related product storage contracts generate revenue from capacity reservations where we collect a fee for reserving storage capacity for customers in our underground storage wells and above-ground storage tanks. Under these agreements, revenue is recognized on a straight-line basis over the reservation period. In addition, we generally charge customers throughput fees based on volumes delivered into and subsequently withdrawn from storage, which are recognized as the service is provided.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NGL import and export terminaling activities generate revenue in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded.

Crude Oil Pipelines & Services

Sales of crude oil
Crude oil marketing activities generate revenues from the sale and delivery of crude oil purchased either directly from producers or on the open market. Revenue from these sales contracts is recognized when crude oil is sold and delivered to customers at market-based prices.

Midstream services
Crude oil transportation contracts and tariffs generate revenue based upon a fixed fee per barrel multiplied by the volume transported and delivered (or capacity reserved). Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Under certain agreements, customers are required to ship a minimum volume over an agreed-upon period, with make-up rights. Revenue pursuant to such agreements is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the likelihood of the shipper's ability to meet the minimum volume commitment becomes remote, or when the pipeline is otherwise released from its performance obligation.

Crude oil storage contracts generate revenue from capacity reservations where we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized on a straight-line basis over the reservation period. In addition, customers are billed a fee per unit of volume loaded or unloaded at our terminals. Revenue is recognized as the service is provided.

Natural Gas Pipelines & Services

Sales of natural gas
Natural gas marketing activities generate revenue from the sale and delivery of natural gas purchased from producers, regional natural gas processing plants and on the open market. Revenue from these sales contracts is recognized when natural gas is sold and delivered to customers at market-based prices.

Midstream services
Natural gas transportation contracts generate revenues based on a fee per unit of volume transported multiplied by the volume gathered or delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Certain of our natural gas pipelines offer firm capacity reservation services whereby the shipper pays a contractual fee based on the level of throughput capacity reserved. Revenues are recognized when the volumes are transported and delivered to customers or in the period we provide firm capacity services for the shipper.

Petrochemical & Refined Products Services

Sales of petrochemicals and refined products
Our petrochemical marketing activities include the purchase and fractionation of refinery grade propylene obtained on the open market and generate revenues from the sale and delivery of polymer grade propylene to customers at market-based prices. Revenues from our PDH facility are dependent on the level of minimum volume commitments by customers and the associated contractual fees paid by them for polymer grade propylene during a given period.

Revenue from the production and sale of octane additives and high purity isobutylene is dependent on the volume of such commodities sold and delivered to customers at market-based prices.

Revenue from refined products marketing is dependent on the volume of such commodities purchased on the open market and sold and delivered to customers at market-based prices.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Midstream services
Propylene fractionation and butane isomerization facilities generate revenue through fee-based toll arrangements with customers, with such arrangements typically including a base-processing fee subject to adjustment for changes in power, fuel and labor costs. Revenue resulting from such agreements is recognized in the period the services are provided.

Petrochemical and refined products transportation contracts generate revenue based upon a fixed fee per volume multiplied by the volume transported and delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies or contractual arrangements. Marine transportation contracts generate revenue based on set day rates or a set fee per cargo movement recognized over the transit time of individual tows. Additionally, we record revenue for the costs of fuel and other operating costs that are directly reimbursed by our marine customers.

Refined products storage contracts generate revenue from capacity reservations where we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized on a straight-line basis over the reservation period. In addition, customers are billed a fee per unit of volume loaded or unloaded at our terminals. Revenue is recognized as the service is provided.

Unbilled Revenue and Deferred Revenue

The following table provides information regarding our contract assets and contract liabilities at December 31, 2018:

Contract Asset	Location	Balance
Unbilled revenue (current amount)	Prepaid and other current assets	$ 13.3
Total		$ 13.3

Contract Liability	Location	Balance
Deferred revenue (current amount)	Other current liabilities	$ 80.9
Deferred revenue (noncurrent)	Other long-term liabilities	210.3
Total		$ 291.2

The following table presents significant changes in our unbilled revenue and deferred revenue balances during the year ended December 31, 2018:

	Unbilled Revenue	Deferred Revenue
Balance at January 1, 2018 (upon adoption of ASC 606)	$ --	$ 224.7
Amount included in opening balance transferred to other accounts during period (1)	--	(90.8)
Amount recorded during period	321.7	432.5
Amounts recorded during period transferred to other accounts (1)	(310.6)	(274.8)
Amount recorded in connection with business combination	2.2	--
Other changes	--	(0.4)
Balance at December 31, 2018	$ 13.3	$ 291.2

(1) Unbilled revenues are transferred to accounts receivable once we have an unconditional right to consideration from the customer. Deferred revenues are recognized as revenue upon satisfaction of our performance obligation to the customer.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Remaining Performance Obligations

The following table presents estimated fixed consideration from contracts with customers that contain minimum volume commitments, deficiency and similar fees and the term of the contracts exceeds one year. These amounts represent the revenues we expect to recognize in future periods from these contracts at December 31, 2018. For a significant portion of our revenue, we bill customers a contractual rate for the services provided multiplied by the amount of volume handled in a given period. We have the right to invoice the customer in the amount that corresponds directly with the value of our performance completed to date. Therefore, we are not required to disclose information about the variable consideration of remaining performance obligations as we recognize revenue equal to the amount that we have the right to invoice.

2019	2020	2021	2022	2023	Thereafter	Total
$3,530.6	$3,187.3	$2,641.4	$2,145.0	$1,798.7	$7,289.9	$20,592.9

Impact of Change in Accounting Policy – ASC 606 Transition Disclosures

The following information and tables are provided to summarize the impacts of adopting ASC 606 on our consolidated financial statements for the year ended December 31, 2018.

As noted previously, additional service revenue and related inventory is now recognized in connection with the equity NGL volumes (a form of non-cash consideration) we receive under natural gas processing agreements. When the inventory is sold through our NGL marketing activities, we reflect additional cost of sales amounts within our operating costs and expenses.

Unbilled revenues have historically been presented as a component of accounts receivable on our consolidated balance sheets. Upon implementation of ASC 606, we reclassified these amounts to “Prepaid and other current assets” since these amounts represent conditional rights to consideration. Once we have an unconditional right to consideration, the amount is transferred to accounts receivable.

Historically, amounts received from customers as CIACs related to pipeline construction activities and production well tie-ins have been netted against property, plant and equipment on our consolidated balance sheets and presented as a cash inflow within the investing activities section of our statements of consolidated cash flows. Upon implementation of ASC 606, these amounts are now recognized as a component of midstream service revenue on our statement of operations and are a component of cash provided by operating activities as presented on our statements of consolidated cash flows.

Consolidated Balance Sheet Information at December 31, 2018

	Impact of change in accounting policy		
	Balances without adoption of ASC 606	Impact of adoption of ASC 606	As Reported
Assets			

Accounts receivable – trade, net	$3,672.4	$ (13.3)	$3,659.1
Prepaid and other current assets	298.2	13.3	311.5
Property, plant and equipment, net	38,639.3	98.3	38,737.6
Liabilities and Equity			
Other current liabilities	404.3	0.5	404.8
Other long-term liabilities	664.8	86.8	751.6
Partners' equity	23,842.5	11.0	23,853.5

The impact of adoption of ASC 606 includes the reclassification of unbilled revenue amounts of $13.3 million from accounts receivable to other current assets.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Statement of Operations Information for the Year Ended December 31, 2018

	Impact of change in accounting policy		
	Balances without adoption of ASC 606	Impact of adoption of ASC 606	As Reported
Revenues	$35,901.5	$ 632.7	$36,534.2
Costs and expenses:			
Operating costs and expenses:	30,775.6	621.7	31,397.3

The impact of adopting ASC 606 on revenues for the year ended December 31, 2018 includes the recognition of $621.7 million of revenues from non-cash consideration (i.e., equity NGLs) earned when providing natural gas processing services and $11.0 million recognized in connection with CIACs. Operating costs and expenses for the year ended December 31, 2018 includes $621.7 million attributable to cost of sales recognized when the equity NGL products were sold and delivered to customers.

Consolidated Statement of Cash Flows Information for the Year Ended December 31, 2018

	Impact of change in accounting policy		
	Balances without adoption of ASC 606	Impact of adoption of ASC 606	As Reported
Operating activities:			
Net income	$4,227.5	$ 11.0	$4,238.5
Net effect of changes in operating accounts	(71.1)	87.3	16.2
Investing activities:			
Contributions in aid of construction costs	87.3	(87.3)	--

Note 10. Business Segments and Related Information

Segment Overview

Our operations are reported under four business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services and (iv) 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.

Financial information regarding these segments is evaluated regularly by our chief operating decision makers in deciding how to allocate resources and in assessing operating and financial performance. The principal executive and financial officers of our general partner have been identified as our chief operating decision makers. While these two officers evaluate results in a number of different ways, the business segment structure is the primary basis for which the allocation of resources and financial results are assessed.

The following information summarizes the assets and operations of each business segment (mileage and other statistics are unaudited):

§ Our NGL Pipelines & Services business segment currently includes our natural gas processing plants and associated NGL marketing activities; approximately 19,200 miles of NGL pipelines; NGL and related product storage facilities; and 16 NGL fractionators. This segment also includes our NGL export docks and related operations.

§ Our Crude Oil Pipelines & Services business segment currently includes approximately 5,300 miles of crude oil pipelines, crude oil storage terminals located in Oklahoma and Texas, and associated crude oil marketing activities.

§ Our Natural Gas Pipelines & Services business segment currently includes approximately 19,700 miles of natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. This segment also includes our natural gas marketing activities.

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

§ Our Petrochemical & Refined Products Services business segment currently includes (i) propylene production facilities, which include our propylene fractionation units and recently completed PDH facility, approximately 800 miles of pipelines, and associated marketing operations; (ii) a butane isomerization complex and related deisobutanizer units; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines aggregating approximately 4,100 miles, terminals and associated marketing activities; and (v) marine transportation.

Our plants, pipelines and other fixed assets are located in the U.S.

Segment Gross Operating Margin

We evaluate segment performance based on our financial measure of gross operating margin. Gross operating margin is an important performance measure of the core profitability of our operations and forms the basis of our internal financial reporting. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. Gross operating margin is exclusive of other income and expense transactions, income taxes, the cumulative effect of changes in accounting principles and extraordinary charges. Gross operating margin is presented on a 100% basis before any allocation of earnings to noncontrolling interests. Our calculation of gross operating margin may or may not be comparable to similarly titled measures used by other companies.

The following table presents our measurement of total segment gross operating margin for the years indicated. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

	For the Year Ended December 31,		
	2018	2017	2016
Operating income	$5,408.6	$3,928.9	$3,580.7
Adjustments to reconcile operating income to total gross operating margin:			
Add depreciation, amortization and accretion expense in operating costs and expenses	1,687.0	1,531.3	1,456.7
Add asset impairment and related charges in operating costs and expenses	50.5	49.8	52.8
Subtract net gains attributable to asset sales in operating costs and expenses	(28.7)	(10.7)	(2.5)
Add general and administrative costs	208.3	181.1	160.1
Adjustments for make-up rights on certain new pipeline projects:			
Add non-refundable payments received from shippers attributable to make-up rights (1)	21.5	24.1	17.5
Subtract the subsequent recognition of revenues attributable to make-up rights (2)	(56.2)	(29.9)	(34.6)
Total segment gross operating margin	$7,291.0	$5,674.6	$5,230.7

(1) Since make-up rights entail a future performance obligation by the pipeline to the shipper, these receipts are recorded as deferred revenue for GAAP purposes; however, these receipts are included in gross operating margin in the period of receipt since they are nonrefundable to the shipper.
(2) As deferred revenues attributable to make-up rights are subsequently recognized as revenue under GAAP, gross operating margin must be adjusted to remove such amounts to prevent duplication since the associated non-refundable payments were previously included in gross operating margin.

The results of operations from our liquids pipelines are primarily dependent upon the volumes transported and the associated fees we charge for such transportation services. Typically, pipeline transportation revenue is recognized when volumes are re-delivered to customers. However, under certain pipeline transportation agreements, customers are required to ship a minimum volume over an agreed-upon period. These arrangements may 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 pursuant to such agreements is initially deferred and subsequently recognized under GAAP at the earlier of when the deficiency volume is shipped, when the likelihood of the shipper's ability to meet the minimum volume commitment becomes remote, or when the pipeline is otherwise released from its performance obligation.

Table of Contents
ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

However, management includes deferred transportation revenues relating to the “make-up rights” of committed shippers when reviewing the financial results of certain new pipeline projects (Texas Express Pipeline, Front Range Pipeline, ATEX, Aegis Ethane Pipeline and Seaway Pipeline). From an internal (and segment) reporting standpoint, management considers the transportation fees paid by committed shippers on these pipeline projects, including any non-refundable revenues that may be deferred under GAAP related to make-up rights, to be important in assessing the financial performance of these pipeline assets. Although the adjustments for make-up rights are included in segment gross operating margin, our consolidated revenues do not reflect any deferred revenues until the conditions for recognizing such revenues are met in accordance with GAAP.

Gross operating margin by segment is calculated by subtracting segment operating costs and expenses from segment revenues, with both segment totals reflecting the adjustments noted in the preceding table, as applicable, and before the elimination of intercompany transactions. The following table presents gross operating margin by segment for the years indicated:

	For the Year Ended December 31,		
	2018	2017	2016
Gross operating margin by segment:			
NGL Pipelines & Services	$3,830.7	$3,258.3	$2,990.6
Crude Oil Pipelines & Services	1,511.3	987.2	854.6
Natural Gas Pipelines & Services	891.2	714.5	734.9
Petrochemical & Refined Products Services	1,057.8	714.6	650.6
Total segment gross operating margin	$7,291.0	$5,674.6	$5,230.7

Summarized Segment Financial Information

Information by business segment, together with reconciliations to amounts presented on our Statements of Consolidated Operations, is presented in the following table:

	Reportable Business Segments					
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:						
Year ended December 31, 2018	$15,630.5	$10,968.2	$3,439.5	$ 6,388.3	$ --	$ 36,426.5
Year ended December 31, 2017	12,455.7	8,137.2	3,132.5	5,471.1	--	29,196.5
Year ended December 31, 2016	10,232.7	6,478.7	2,532.4	3,721.8	--	22,965.6
Revenues from related parties:						
Year ended December 31, 2018	18.4	74.4	14.9	--	--	107.7
Year ended December 31, 2017	12.3	19.6	13.1	--	--	45.0
Year ended December 31, 2016	9.8	36.3	10.6	--	--	56.7
Intersegment and intrasegment revenues:						
Year ended December 31, 2018	26,453.6	35,490.4	721.9	2,917.5	(65,583.4)	--
Year ended December 31, 2017	27,278.6	15,943.0	850.8	1,766.9	(45,839.3)	--

Year ended December 31, 2016	19,150.0	9,052.0	668.5	1,234.8	(30,105.3)	--
Total revenues:						
Year ended December 31, 2018	42,102.5	46,533.0	4,176.3	9,305.8	(65,583.4)	36,534.2
Year ended December 31, 2017	39,746.6	24,099.8	3,996.4	7,238.0	(45,839.3)	29,241.5
Year ended December 31, 2016	29,392.5	15,567.0	3,211.5	4,956.6	(30,105.3)	23,022.3
Equity in income (loss) of unconsolidated affiliates:						
Year ended December 31, 2018	117.0	365.4	6.8	(9.2)	--	480.0
Year ended December 31, 2017	73.4	358.4	3.8	(9.6)	--	426.0
Year ended December 31, 2016	61.4	311.9	3.8	(15.1)	--	362.0

Segment revenues include intersegment and intrasegment transactions, which are generally based on transactions made at market-based rates. Our consolidated revenues reflect the elimination of intercompany transactions. Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base.

Table of Contents

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income. Equity investments with industry partners are a significant component of our business strategy. They are a means by which we conduct our operations to align our interests with those of customers and/or suppliers. This method of operation enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed. Many of these businesses perform supporting or complementary roles to our other midstream business operations.

Our integrated midstream energy asset network (including the midstream energy assets owned by our equity method investees) provides services to producers and consumers of natural gas, NGLs, crude oil, refined products and certain petrochemicals. In general, hydrocarbons may enter our asset system in a number of ways, such as through a natural gas processing plant, a natural gas gathering pipeline, a crude oil pipeline or terminal, an NGL fractionator, an NGL storage facility or an NGL gathering or transportation pipeline. Many of our equity investees are included within our integrated midstream asset network. For example, we use the Front Range Pipeline and Texas Express Pipeline to transport mixed NGLs to our Mont Belvieu NGL fractionation and storage complex and the Seaway Pipeline to transport crude oil to our terminals in the Houston, Texas area. Given the integral nature of our equity method investees to our operations, we believe the presentation of equity earnings from such investees as a component of gross operating margin and operating income is meaningful and appropriate.

Information by business segment, together with reconciliations to our Consolidated Balance Sheet totals, is presented in the following table:

Reportable
Business
Segments
NGL
Pipelines