PBW

Consulting Engineers and Scientists

PASTOR, BEHLING & WHEELER, LLC
2201 Double Creek Drive, Suite 4004
Round Rock, TX 78664

Tel (512) 671-3434
Fax (512) 671-3446

April 8, 2016

VIA ELECTRONIC MAIL

Raji Josiam
Remedial Project Manager
US EPA Region 6
1445 Ross Ave, Suite 1200, 6SF-RA
Dallas, TX 75202

Re: Financial Assurance Demonstration for Remedial Investigation/Feasibility Study (RI/FS) - Area of Investigation 1 (AOI-1) of the USOR Superfund Site, 400 N. Richey Street, Pasadena, Texas

Dear Ms. Josiam:

Pursuant to Section XXVII, Paragraph 106.g of the Administrative Settlement Agreement and Order on Consent for RI/FS (Settlement Agreement) for the above-referenced Site, Pastor, Behling & Wheeler, LLC (PBW), on behalf of the Respondents named in the Settlement Agreement, is herewith submitting the following documents to demonstrate that one or more of the Settling Respondents to the Settlement Agreement have sufficient assets to complete the RI/FS for AOI-1:

- Securities and Exchange Commission (SEC) Form 10-K for Ashland, Inc. for the fiscal year ended September 30, 2015;
- SEC Form 10-K for Clean Harbors, Inc. for the fiscal year ended December 31, 2015; and
- SEC Form 10-K for Enterprise Products Partners L.P. for the fiscal year ended December 31, 2015.

Thank you for the opportunity to submit these documents. Should you have any questions, please do not hesitate to contact me at 512-671-3434.

Sincerely,

Eric F. Pastor
PRP Group Project Coordinator

cc: Mr. Lam Tran – Texas Commission on Environmental Quality

Attachments

9851424

ATTACHMENT A

SEC FORM 10-K FOR ASHLAND, INC.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended September 30, 2015

OR

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

For the transition period from _____ to _____

Commission file number 1-32532

ASHLAND INC.

Kentucky (State or other jurisdiction of incorporation or organization)	20-0865835 (I.R.S. Employer Identification No.)

50 E. RiverCenter Boulevard
P.O. Box 391
Covington, Kentucky 41012-0391
Telephone Number (859) 815-3333

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $.01 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

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

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

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

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

Large Accelerated Filer ☑	Accelerated Filer ☐
Non-Accelerated Filer ☐ (Do not check if a smaller reporting company)	Smaller Reporting Company ☐

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

At March 31, 2015, the aggregate market value of voting stock held by non-affiliates of the Registrant was approximately $8,563,870,000. In determining this amount, the Registrant has assumed that its directors and executive officers are affiliates. Such assumption shall not be deemed conclusive for any other purpose.

At October 31, 2015, there were 66,805,186 shares of Registrant's common stock outstanding.

Documents Incorporated by Reference

Portions of Registrant's Proxy Statement (Proxy Statement) for its January 28, 2016 Annual Meeting of Shareholders are incorporated by reference into Part III of this annual report on Form 10-K to the extent described herein.

TABLE OF CONTENTS

			Page
PART I			
	Item 1.	Business	1
		General	1
		Corporate Developments	2
		Ashland Specialty Ingredients	2
		Ashland Performance Materials	4
		Valvoline	4
		Miscellaneous	5
	Item 1A.	Risk Factors	8
	Item 1B.	Unresolved Staff Comments	14
	Item 2.	Properties	14
	Item 3.	Legal Proceedings	14
	Item 4.	Mine Safety Disclosures	16
	Item X.	Executive Officers of Ashland	16
PART II			
	Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Purchases of Equity Securities	17
	Item 6.	Selected Financial Data	19
	Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operation	19
	Item 7A.	Quantitative and Qualitative Disclosures about Market Risk	19
	Item 8.	Financial Statements and Supplementary Data	19
	Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	19
	Item 9A.	Controls and Procedures	19
	Item 9B.	Other Information	19
PART III			
	Item 10.	Directors, Executive Officers and Corporate Governance	19
	Item 11.	Executive Compensation	20
	Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	20
	Item 13.	Certain Relationships and Related Transactions, and Director Independence	22
	Item 14.	Principal Accounting Fees and Services	22
PART IV			
	Item 15.	Exhibits and Financial Statement Schedules	22

PART I

ITEM 1. BUSINESS

GENERAL

Ashland Inc. is a Kentucky corporation, with its principal executive offices located at 50 E. RiverCenter Boulevard, Covington, Kentucky 41011 (Mailing Address: 50 E. RiverCenter Boulevard, P.O. Box 391, Covington, Kentucky 41012-0391) (Telephone: (859) 815-3333). Ashland was organized in 2004 as the successor to a Kentucky corporation of the same name organized on October 22, 1936. The terms "Ashland" and the "Company" as used herein include Ashland Inc., its predecessors and its consolidated subsidiaries, except where the context indicates otherwise.

Ashland is a global leader in specialty chemicals and, through Valvoline, a premium consumer-branded lubricant supplier. Ashland provides products, services and solutions that meet customers' needs throughout a variety of industries in more than 100 countries. Its chemistry is used in a wide variety of markets and applications, including architectural coatings, adhesives, automotive, construction, energy, food and beverage, personal care, and pharmaceutical.

Ashland has three reportable segments: Specialty Ingredients, Performance Materials and Valvoline. Financial information about Ashland's three reportable segments for each of the fiscal years in the three-year period ended September 30, 2015 is set forth in Note Q of Notes to Consolidated Financial Statements in this annual report on Form 10-K, including sales, equity income, other income, operating income and assets. International data, such as sales to external customers, net assets and property, plant and equipment, are set forth in Note Q as well.

Specialty Ingredients is a global leader in cellulose ethers, vinyl pyrrolidones and biofunctionals. It offers industry-leading products, technologies and resources for solving formulation and product-performance challenges. Specialty Ingredients uses natural, synthetic and semisynthetic polymers derived from plant and seed extract, cellulose ethers, vinyl pyrrolidones, acrylic polymers as well as polyester and polyurethane-based adhesives. Specialty Ingredients includes two divisions - Consumer Specialties and Industrial Specialties - that offer comprehensive and innovative solutions for today's demanding consumer and industrial applications. Key customers include: pharmaceutical companies; makers of personal care products, food and beverages; manufacturers of paint, coatings and construction materials; packaging and converting; and oilfield service companies. During 2015, Ashland sold the industrial biocides assets within Specialty Ingredients. See Note B of Notes to Consolidated Financial Statements in this annual report on Form 10-K for information on the divestiture of these assets.

Performance Materials is composed of two divisions: Composites and Intermediates/Solvents. Performance Materials is a global leader in unsaturated polyester resins and vinyl ester resins. The business unit has leading positions in gelcoats, maleic anhydride, butanediol, tetrahydrofuran, N-Methylpyrrolidone and other intermediates and solvents. Key customers include: manufacturers of residential and commercial building products; industrial product specifiers and manufacturers; wind blade and pipe manufacturers; automotive and truck OEM suppliers; boatbuilders; engineered plastics and electronic producers; and specialty chemical manufacturers. Results from the former Elastomers division were included in Performance Materials' results of operations within the Statements of Consolidated Comprehensive Income until its December 1, 2014 sale. See Note B for information on the divestiture of the Elastomers division.

Valvoline is a leading, worldwide producer and distributor of premium-branded automotive, commercial and industrial lubricants and automotive chemicals. It ranks as the #2 quick-lube chain and #3 passenger car motor oil brand in the United States. The brand operates and franchises approximately 940 Valvoline Instant Oil Change℠ centers in the United States. It also markets Valvoline™ lubricants and automotive chemicals; MaxLife™ lubricants created for higher-mileage engines; SynPower™ synthetic motor oil; and Zerex™ antifreeze. Key customers include: retail auto parts stores and mass merchandisers who sell to consumers; installers, such as car dealers, repair shops and quick lubes; commercial fleets; and distributors. During 2015, Ashland sold its Valvoline car care product assets, including Car Brite™ and Eagle One™ automotive appearance products, and sold its joint venture equity investment in Venezuela. See Note B for information on the divestitures of this investment and the car care product assets.

At September 30, 2015, Ashland and its consolidated subsidiaries had approximately 10,500 employees (excluding contract employees).

Available Information – Ashland's Internet address is *http://www.ashland.com*. On this website, Ashland makes available, free of charge, its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports, as well as any beneficial ownership reports of officers and directors filed on Forms 3, 4 and 5. All such reports are available as soon as reasonably practicable after they are electronically filed with, or electronically furnished to, the Securities and Exchange Commission (SEC). Ashland also makes available, free of charge on its website, its Corporate Governance Guidelines, Board Committee Charters, Director Independence Standards and code of business conduct that applies to Ashland's directors, officers and employees. These documents are also available in print to any shareholder who requests them. Information contained on Ashland's website is not part of this annual report on Form 10-K and is not incorporated by reference in this document. The public may read and copy any materials Ashland files with the SEC at the SEC's Public Reference Room at 100

F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (http://www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

CORPORATE DEVELOPMENTS

On September 22, 2015, Ashland announced that the Board of Directors approved proceeding with a plan to separate Ashland into two independent, publicly traded companies comprising of the new Ashland and Valvoline. Ashland has begun the process to separate its Valvoline business from its Specialty Ingredients and Performance Materials businesses while it finalizes the transaction structure and obtains customary regulatory and other approvals. Ashland intends for the separation, which is subject to final board approval prior to completion, to be tax free for Ashland shareholders. Immediately following the separation, Ashland shareholders will own shares of both the new Ashland and Valvoline. The separation is expected to be completed as soon as practicable, but not before the end of fiscal 2016.

The new Ashland will be a global leader in providing specialty chemical solutions to customers in a wide range of consumer and industrial markets. These markets are currently served by Specialty Ingredients and Performance Materials. Key markets and applications include pharmaceutical, personal care, food and beverage, architectural coatings, adhesives, automotive, construction and energy. Together these businesses generated approximately $3.4 billion in sales for the fiscal year ended September 30, 2015.

Valvoline will focus on building the world's leading engine and automotive maintenance business by providing hands-on expertise to customers in each of its primary market channels: Do-It-Yourself (DIY); Installers; Valvoline Instant Oil Change^{SM}; and International. Valvoline generated sales of $2.0 billion for Ashland during the fiscal year ended September 30, 2015.

ASHLAND SPECIALTY INGREDIENTS

Ashland Specialty Ingredients (Specialty Ingredients) offers industry-leading products, technologies and resources for solving formulation and product-performance challenges. Using natural, synthetic and semisynthetic polymers derived from plant and seed extract, cellulose ethers, vinyl pyrrolidones, acrylic polymers as well as polyester and polyurethane-based adhesives, Specialty Ingredients offers comprehensive and innovative solutions for consumer and industrial applications.

Key customers include pharmaceutical companies; makers of personal care products, food and beverages; manufacturers of paint, coatings and construction materials; packaging and converting; and oilfield service companies. Certain customer relationships are significant, and the loss of any one of those customers could have a material adverse effect on the Specialty Ingredients reportable segment.

Specialty Ingredients' areas of expertise include: organic and synthetic chemistry, polymer chemistry, surface and colloid science, rheology, structural analysis and microbiology.

Specialty Ingredients' solutions provide an array of properties, including: thickening and rheology control, water retention, adhesive strength, binding power, film formation, conditioning and deposition, colloid stabilization and suspension.

Specialty Ingredients is composed of two divisions: Consumer Specialties and Industrial Specialties. These divisions are defined based on end use markets of customers, but significant overlap of underlying product lines between the two divisions exists and many of the products are produced in shared manufacturing facilities, in order to better manage capacity and achieve desired returns.

Consumer Specialties – The Consumer Specialties division includes the Oral Care, Hair Care, Skin Care, Home Care and Pharmaceutical & Nutrition portfolios.

- Oral Care – Specialty Ingredients' portfolio of oral care products delivers active ingredients in toothpaste and mouthwashes; provides bioadhesive functionality for dentures; delivers flavor, texture and other functional properties; and provides product binding to ensure form and function throughout product lifecycle.
- Hair Care – Specialty Ingredients' portfolio of hair care products includes advanced styling polymers, fixatives, conditioning polymers, emulsifiers, preservatives and rheology modifiers.
- Skin Care – Specialty Ingredients' portfolio of skin care products helps to firm, nourish, revitalize and smooth skin. The Skin Care line also provides sun care products, including UV filters, water-resistant agents and thickeners. Emulsifiers, emollients, preservatives and rheology modifiers complete the Skin Care product line.
- Home Care – Specialty Ingredients' portfolio of products and technologies is used in many types of cleaning applications, including fabric care, home care and dishwashing. Specialty Ingredients' products are used in a variety of applications for viscosity enhancement, particle suspension, rheology modification and stabilization.

- Pharmaceutical – Specialty Ingredients is a leading supplier of excipients and tablet coating systems to the pharmaceutical and nutraceutical industries. The excipients division offers a comprehensive range of polymers for use as tablet binders, superdisintegrants, sustained-release agents and drug solubilizers, as well as a portfolio of fully formulated, one-step tablet coating systems for immediate-, sustained- and delayed-release applications.
- Nutrition – Specialty Ingredients' nutrition portfolio provides functional benefits in areas such as thickening, texture control, thermal gelation, structure enhancement, water binding, clarification and stabilization. Its core products include cellulose gums and vinyl pyrrolidone polymers which are used in a wide range of offerings for bakery, beverage, dairy, desserts, meat products, pet food, prepared foods, sauces and savory products.

Industrial Specialties – The Industrial Specialties division includes Coatings, Construction, Energy, Adhesives and Performance Specialties.

- Coatings – Coatings Specialties is a recognized leader in rheology solutions for waterborne architectural paint and coatings. Products include hydroxyethylcellulose (HEC), which provides thickening and application properties for interior and exterior paints, and nonionic synthetic associative thickeners (NSATs), which are APEO-free liquid synthetics for high-performance paint and industrial coatings. The Coatings Specialties market complements its rheology offering with a broad portfolio of performance foam-control agents, surfactants and wetting agents, dispersants and pH neutralizers.
- Construction – Construction Specialties is a major producer and supplier of cellulose ethers and companion products for the construction industry. These products control properties such as water retention, open time, workability, adhesion, stabilization, pumping, sag resistance, rheology, strength, appearance and performance in dry-mortar formulations.
- Energy – Energy Specialties is a leading global manufacturer of guar-, synthetic- and cellulosic-based products for drilling fluids, oil-well cement slurries, completion and workover fluids, fracturing fluids and production chemicals. Specialty Ingredients offers the oil and gas industry solutions for drilling, stimulation, completion, cementing and production applications.
- Adhesives – Adhesives Specialties manufactures and sells adhesive solutions to the packaging and converting, building and construction, and transportation markets and manufactures and markets specialty coatings and adhesive solutions for use across multiple industries. Key technologies and markets include: acrylic polymers for pressure-sensitive adhesives; urethane adhesive for flexible packaging applications; aqueous and radiation-curable adhesives and specialty coatings for printing and converting applications; emulsion polymer isocyanate adhesives for structural wood bonding; elastomeric polymer adhesives for commercial roofing applications; acrylic, polyurethane and epoxy structural adhesives for bonding fiberglass reinforced plastics, composites, thermoplastics and metals in automotive, marine, recreational and industrial applications; specialty phenolic resins for paper impregnation and friction material bonding. Adhesive Specialties' adhesive products provide an array of functional properties including high-strength bonding, ease and speed of product assembly, heat and moisture resistance and design flexibility.
- Performance – Performance Specialties provides products and services to over 30 industries. Ashland offers a broad spectrum of organo- and water-soluble polymers that are derived from both natural and synthetic resources. Product lines include derivatized cellulose polymers, synthetics, guar and guar derivatives that impart effective functionalities to serve a variety of industrial markets and specialized applications. Many of the products within Performance Specialties function as performance additives that deliver high levels of end-user value in formulated products. In other areas, such as plastics and textiles, Performance Specialties' products function as a processing aid, improving the quality of end products and reducing manufacturing costs.

Specialty Ingredients' cellulosics products were approximately 37% and 16% of Specialty Ingredients' sales and Ashland's consolidated sales, respectively, for fiscal 2015.

Specialty Ingredients operates throughout the Americas, Europe and Asia Pacific. It has 26 manufacturing facilities in eight countries which serve both the Consumer Specialties and Industrial Specialties divisions and participates in two joint ventures. Specialty Ingredients has manufacturing facilities in Huntsville, Alabama; Wilmington, Delaware; Dalton, Georgia; Calumet City, Illinois; Calvert City, Kentucky; Freetown, Massachusetts; Chatham and Parlin, New Jersey; Columbus, Hilliard and Ashland, Ohio; White City, Oregon; Piedmont, South Carolina; Kenedy and Texas City, Texas and Hopewell, Virginia within the United States and Doel-Beveren, Belgium; Cabreuva, Brazil; Jiangmen and Nanjing, China; Alizay and Sophia Antipolis, France; Memmingen, Germany; Zwijndrecht, the Netherlands and Kidderminster, Newton Aycliffe and Poole, United Kingdom. Specialty Ingredients also operates two production facilities through a joint venture in Luzhou and Suzhou, China.

Specialty Ingredients markets and distributes its products and services directly and through third-party distributors in the Americas, Europe, the Middle East, Africa and Asia Pacific.

ASHLAND PERFORMANCE MATERIALS

Ashland Performance Materials (Performance Materials) is a global leader in unsaturated polyester resins and vinyl ester resins. The business unit has leading positions in gelcoats, maleic anhydride, butanediol, tetrahydrofuran, N-Methylpyrrolidone and other intermediates and solvents. Performance Materials' Composites division is a global leader helping customers create stronger, lighter, more resistant substitutes for traditional materials through higher performing, cost-efficient resin technologies that improve the manufacturing, fabrication and design process. Applied industries include construction, transportation, infrastructure, and boatbuilding. The Intermediates and Solvents division provides butanediol and its derivatives to the chemical process industry, plastics manufacturers, and electronics markets, among others. Prior to the December 1, 2014 sale, the Elastomers division provided high-quality styrene butadiene rubber primarily to the replacement tire market.

Key customers include manufacturers of residential and commercial building products, industrial product specifiers and manufacturers, wind blade manufacturers, pipe manufacturers, automotive and truck OEM suppliers, boatbuilders, chemical producers and electronics makers.

Performance Materials is composed of the following divisions:

Composites – The Composites division manufactures and sells a broad range of general-purpose and high-performance grades of unsaturated polyester and vinyl ester resins, gelcoats and low-profile additives for the reinforced plastics industry. Key markets include the transportation, construction, marine and infrastructure end markets. Performance Materials' composite products provide an array of functional properties including corrosion resistance, fire retardance, ultraviolet resistance, water and chemical resistance, high mechanical strength, impact and scratch resistance and high strength-to-weight ratios. In addition, the division also manufactures and sells molten maleic anhydride for the manufacture of a variety of products such as unsaturated polyester resins, copolymers, lubricating oil additives, alkenyl succinic anhydrides, malic acid, fumaric acid and numerous derivative chemicals. Molten maleic anhydride is supplied both to Ashland businesses who consume it as a raw material, primarily in North America, and to the merchant market.

Intermediates and Solvents – The Intermediates and Solvents (I&S) division is a leading producer of 1,4 butanediol and its derivatives, including tetrahydrofuran and n-methylpyrrolidone. These products are used as chemical intermediates in the production of engineering polymers and polyurethanes, and as specialty process solvents in a wide array of applications including electronics, construction, and active pharmaceutical ingredient manufacture. Butanediol is also supplied to Specialty Ingredients for use as a raw material.

Performance Materials' composites products were approximately 68% and 15% of Performance Materials' sales and Ashland's total consolidated sales, respectively, for fiscal 2015.

Performance Materials operates throughout the Americas, Europe and Asia Pacific. It has 15 manufacturing facilities in seven countries. Composites has manufacturing plants in Fort Smith and Jacksonville, Arkansas; Commerce, California; Bartow, Florida; Neville Island and Philadelphia, Pennsylvania; and Neal, West Virginia within the United States and Aracariguama, Brazil; Changzhou, China; Porvoo, Finland; Miszewo, Poland; and Benicarló, Spain. I&S has manufacturing facilities in Lima, Ohio and Marl, Germany. Performance Materials also provides toll manufacturing services to ASK Chemicals GmbH through manufacturing facilities located in Changzhou, China. ASK Chemical GmbH was a joint venture in which Ashland held a 50% interest until its interest was sold on June 30, 2014.

Performance Materials markets and distributes its products directly and through third-party distributors in the Americas, Europe, the Middle East, Africa and Asia Pacific.

VALVOLINE

Valvoline delivers premium-branded automotive, commercial and industrial lubricants and automotive chemicals. It operates and franchises approximately 940 Valvoline Instant Oil Change^{SM} centers in the United States. It markets Valvoline™ lubricants and automotive chemicals; MaxLife™ lubricants for cars with higher mileage engines; SynPower™ synthetic motor oil; and Zerex™ antifreeze.

Key customers include retail auto parts stores and mass merchandisers who sell to consumers; installers, such as car dealers, repair shops and quick lubes; commercial fleets; and distributors. Certain customer relationships are significant, and the loss of any one of those customers could have a material adverse effect on the Valvoline business unit.

The Valvoline reportable segment is composed of the following markets:

Do It Yourself (DIY) – The DIY unit sells Valvoline™ and other branded and private label products to consumers who perform their own auto maintenance. These products are sold through retail auto parts stores such as AutoZone, O'Reilly Auto Parts,

Advance Auto Parts, mass merchandisers such as Wal-Mart Stores, Inc., and warehouse distributors and their affiliated jobber stores such as NAPA and CARQUEST.

Installer Channels – The Installer Channels unit sells branded products and services to installers (such as car dealers, general repair shops and quick lubes) through a network of independent distributors and company-owned and operated "direct market" operations as well as national accounts such as Goodyear, Monro and Sears. The division also sells branded products and services to on-highway fleets and construction companies through company-owned and operated "direct market" operations, national accounts and a network of distributors. The Installer Channels has a relationship with Cummins Inc. (Cummins) for co-branding in the North America Heavy Duty business. During fiscal 2015, Ashland sold its Valvoline car care product assets.

Valvoline Instant Oil Change (VIOC) – The Valvoline Instant Oil Change^{SM} chain is the second largest competitor in the U.S. "fast oil change" service business, providing Valvoline with a significant presence in the installer channels segment of the passenger car and light truck motor oil market. As of September 30, 2015, 279 company-owned and 663 independently-owned and operated franchise VIOC centers were operating in 43 states. VIOC centers offer customers an innovative computer-based preventive maintenance tracking system that allows service technicians to make service recommendations based primarily on manufacturers' recommendations. In addition, this division includes distribution to quick lubes branded "Valvoline Express Care™," which consists of 328 independently-owned and operated stores.

Valvoline International – Outside of North America, Valvoline International markets Valvoline™, Zerex™ and other branded products through wholly-owned affiliates, joint ventures, licensees and independent distributors in over 138 countries. Valvoline International operates joint ventures with Cummins in Argentina, China and India. In addition, Valvoline International operates joint ventures with local entities in Colombia, Ecuador and Thailand. Valvoline International markets products for both consumer and commercial vehicles and equipment and is served by company-owned plants in the United States, Australia and the Netherlands and by numerous third-party warehouses and toll manufacturers throughout the world.

Valvoline International sells branded products and services to original equipment manufacturers (OEMs) through company-owned and operated "direct market" operations, national accounts and a network of distributors. Valvoline International also maintains a strategic alliance with Cummins to distribute heavy duty lubricants to the commercial market, as well as smaller alliances with other global OEMs.

Valvoline's lubricants products were approximately 86% and 31% of Valvoline's and Ashland's total consolidated sales, respectively, for fiscal 2015.

Valvoline operates lubricant blending and packaging plants in Santa Fe Springs, California; Cincinnati, Ohio; East Rochester, Pennsylvania and Deer Park, Texas within the United States and Wetherill Park, Australia and Dordrecht, the Netherlands. Bulk blending and distribution facilities are located in College Park, Georgia; Willow Springs, Illinois and St. Louis, Missouri within the United States and Mississauga, Canada. Distribution operations are conducted from centers located in College Park, Georgia; Willow Springs, Illinois; Noblesville, Indiana; St. Louis, Missouri; Cincinnati, Ohio and East Rochester, Pennsylvania within the United States and through owned facilities in Birkenhead, United Kingdom and leased facilities in Sydney, Australia and Dordrecht, the Netherlands. Valvoline also uses property owned and operated by third-parties in Pasadena and Highlands, Texas in the United States; Rotterdam, the Netherlands, and other smaller locations, and is a part of a joint venture that operates a plant in Ambarnath, India.

In addition to raw materials, Valvoline sources a significant portion of packaging and third party products and services.

MISCELLANEOUS

Environmental Matters

Ashland maintains a companywide environmental policy overseen by the Environmental, Health, Safety and Product Compliance Committee of Ashland's Board of Directors. Ashland's Environmental, Health, Safety and Product Regulatory (EHS&PR) department has the responsibility to ensure that Ashland's businesses worldwide maintain environmental compliance in accordance with applicable laws and regulations. This responsibility is carried out via training; widespread communication of EHS&PR policies; information and regulatory updates; formulation of relevant policies, procedures and work practices; design and implementation of EHS&PR management systems; internal auditing by a separate auditing group; monitoring of legislative and regulatory developments that may affect Ashland's operations; assistance to the businesses in identifying compliance issues and opportunities for voluntary actions that go beyond compliance; and incident response planning and implementation.

Federal, state and local laws and regulations relating to the protection of the environment have a significant impact on how Ashland conducts its businesses. In addition, Ashland's operations outside the United States are subject to the environmental laws of the countries in which they are located. These laws include regulation of air emissions and water discharges, waste handling, remediation and product inventory, registration and regulation. New laws and regulations may be enacted or adopted by various

regulatory agencies globally. The costs of compliance with any new laws or regulations cannot be estimated until the manner in which they will be implemented has been more precisely defined.

At September 30, 2015, Ashland's reserves for environmental remediation and related environmental litigation amounted to $186 million, reflecting Ashland's estimates of the most likely costs that will be incurred over an extended period to remediate identified conditions for which the costs are reasonably estimable, without regard to any third-party recoveries. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated reserves for environmental remediation. Environmental remediation reserves are subject to numerous inherent uncertainties that affect Ashland's ability to estimate its share of the costs. Such uncertainties involve the nature and extent of contamination at each site, the extent of required cleanup efforts under existing environmental regulations, widely varying costs of alternate cleanup methods, changes in environmental regulations, the potential effect of continuing improvements in remediation technology and the number and financial strength of other potentially responsible parties at multiparty sites. Although it is not possible to predict with certainty the ultimate costs of environmental remediation, Ashland currently estimates that the upper end of the reasonably possible range of future costs for identified sites could be as high as approximately $370 million. No individual remediation location is significant, as the largest reserve for any site is approximately 14% or less of the remediation reserve. Ashland continues to discount certain environmental sites and regularly adjusts its reserves as environmental remediation continues. Environmental remediation expense, net of insurance receivables, amounted to $40 million in 2015, compared to $33 million in 2014 and $29 million in 2013.

Product Control, Registration and Inventory – Many of Ashland's products and operations are subject to chemical control laws of the countries in which they are located. These laws include regulation of chemical substances and inventories under the Toxic Substances Control Act (TSCA) in the United States and the Registration, Evaluation and Authorization of Chemicals (REACH) regulation in Europe. Under REACH, additional testing requirements, documentation, risk assessments and registrations are occurring and will continue to occur and may adversely affect Ashland's costs of products produced in or imported into the European Union. Examples of other product control regulations include right to know laws under the Global Harmonized System (GHS) for hazard communication, regulation of chemicals used in the manufacture of pharmaceuticals and personal care products and that contact food under the Food, Drug and Cosmetics Act in the United States, the Framework Regulation in Europe and other product control requirements for chemical weapons, drug precursors and import/export. New laws and regulations may be enacted or adopted by various regulatory agencies globally. The costs of compliance with any new laws or regulations cannot be estimated until the manner in which they will be implemented has been more precisely defined.

Remediation – Ashland currently operates, and in the past has operated, various facilities at which, during the normal course of business, releases of hazardous substances have occurred. Additionally, Ashland has known or alleged potential environmental liabilities at a number of third-party sites. Federal and state laws, including but not limited to the Resource Conservation and Recovery Act (RCRA), the Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and various other remediation laws, require that contamination caused by hazardous substance releases be assessed and, if necessary, remediated to meet applicable standards. Some of these laws also provide for liability for related damage to natural resources, and claims for alleged property and personal injury damage can also arise related to contaminated sites. Laws in other jurisdictions in which Ashland operates require that contamination caused by such releases at these sites be assessed and, if necessary, remediated to meet applicable standards.

Air – In the United States, the Clean Air Act (CAA) imposes stringent limits on facility air emissions, establishes a federally mandated operating permit program, allows for civil and criminal enforcement actions and sets limits on the volatile or toxic content of many types of industrial materials and consumer products. The CAA establishes national ambient air quality standards (NAAQS) with attainment deadlines and control requirements based on the severity of air pollution in a given geographical area. Various state clean air acts implement, complement and, in many instances, add to the requirements of the federal CAA. The requirements of the CAA and its state counterparts have a significant impact on the daily operation of Ashland's businesses and, in many cases, on product formulation and other long-term business decisions. Other countries where Ashland operates also have laws and regulations relating to air quality. Ashland's businesses maintain numerous permits and emission control devices pursuant to these clean air laws.

The United States Environmental Protection Agency (USEPA) has increased its frequency in reviewing the NAAQS. The USEPA has stringent standards for particulate matter, ozone and sulfur dioxide. Throughout 2015, state and local agencies continued to implement options for meeting the newest standards. Particulate matter strategies include dust control measures for construction sites and reductions in emission rates allowed for industrial operations. Options for ozone include emission controls for certain types of sources, reduced limits on the volatile organic compound content of industrial materials and consumer products, and requirements on the transportation sector. Most options for sulfur dioxide focus on coal and diesel fuel combustion sources. It is not possible at this time to estimate the potential financial impact that these newest standards may have on Ashland's operations or products. Ashland will continue to monitor and evaluate these standards to meet these and all air quality requirements.

Solid Waste – Ashland's businesses are subject to various laws relating to and establishing standards for the management of hazardous and solid waste. In the United States, Ashland's facilities are subject to RCRA and its regulations governing generators of hazardous waste. Ashland has implemented systems to oversee compliance with the RCRA regulations. In addition to regulating current waste disposal practices, RCRA also addresses the environmental effects of certain past waste disposal operations, the recycling of wastes and the storage of regulated substances in underground tanks. Ashland has the remediation liability for certain facilities subject to these regulations. Other countries where Ashland operates also have laws and regulations relating to hazardous and solid waste, and Ashland has systems in place to oversee compliance.

Water – Ashland's businesses maintain numerous discharge permits. In the United States, such permits may be required by the National Pollutant Discharge Elimination System of the Clean Water Act and similar state programs. Other countries have similar laws and regulations requiring permits and controls relating to water discharge.

Climate Change and Related Regulatory Developments – Ashland has been collecting energy use data and calculating greenhouse gas (GHG) emissions for many years. Ashland evaluates the potential impacts from both climate change and the anticipated GHG regulations to facilities, products and other business interests, as well as the strategies commonly considered by the industrial sector to reduce the potential impact of these risks. These risks are generally grouped as impacts from legislative, regulatory and international developments, impacts from business and investment trends and impacts to company assets from the physical effects of climate change. Current North American, European and other regional regulatory developments are not expected to have a material effect on Ashland's operations, although some facilities are subject to promulgated rules. Business and investment trends are expected to drive an increase in the demand for products that improve energy efficiency, reduce energy use and increase the use of renewable resources. At this time, Ashland cannot estimate the impact of this expected demand increase to its businesses. Physical effects from climate change have the potential to affect Ashland's assets in areas prone to sea level rise or extreme weather events much as they do the general public and other businesses. Due to the uncertainty of these matters, Ashland cannot estimate the impact at this time of GHG-related developments on its operations or financial condition.

Competition

Specialty Ingredients and Performance Materials compete in the highly fragmented specialty chemicals industry. The participants in the industry offer a varied and broad array of product lines designed to meet specific customer requirements. Participants compete with individual and service product offerings on a global, regional and/or local level subject to the nature of the businesses and products, as well as the end-markets and customers served. Competition is based on several key criteria, including product performance and quality, product price, product availability and security of supply, responsiveness of product development in cooperation with customers, customer service, industry knowledge and technical capability. Certain key competitors are significantly larger than Ashland and have greater financial resources, leading to greater operating and financial flexibility. The industry has become increasingly global as participants have focused on establishing and maintaining leadership positions outside of their home markets. Many of these segments' product lines face domestic and international competition, as a result of industry consolidation, pricing pressures and competing technologies.

Valvoline competes in the highly competitive automotive lubricants business, principally through its offerings of premium products and services primarily under the Valvoline™ family of trademarks, coupled with strong brand marketing, customer support and distribution capabilities. Some of the major brands of motor oils and lubricants with which Valvoline competes globally are Castrol†, Mobil† and Pennzoil†. In the "fast oil change" market, Valvoline competes with other leading independent fast lube chains on a national, regional or local basis, as well as automobile dealers and service stations. Important competitive factors for Valvoline in the "fast oil change" market include the Valvoline brand recognition; maintaining market presence through Valvoline Instant Oil Change℠ and Valvoline Express Care™ outlets; and quality and speed of service, location, convenience, sales promotions and other value-add elements.

Intellectual Property

Ashland has a broad intellectual property portfolio which is an important component of all of Ashland's reportable segments. In particular, Ashland's Specialty Ingredients and Performance Materials reportable segments rely on patents, trade secrets, formulae and know-how to protect and differentiate their products and technologies. In addition, these reportable segments own valuable trademarks which identify and differentiate Ashland's products from its competitors. The Valvoline™ trademark and other trademarks related to Valvoline brand products and franchises are of particular importance to the Valvoline brand segment and the overall Ashland business. Ashland also licenses intellectual property rights from third-parties.

Raw Materials

Ashland purchases its raw materials from multiple sources of supply in the United States and other countries, and believes that raw material supplies will be available in quantities sufficient to meet demand in fiscal 2016. All of Ashland's reportable segments were impacted to varying degrees in fiscal 2015 by the volatility of raw materials costs, and these conditions may continue in fiscal 2016.

Research and Development

Ashland's program of research and development is focused on defining the needs of the marketplace and framing those needs into technology platforms. Ashland has the capability to deliver and develop the intellectual property required to grow and protect those platforms. Ashland is focused on developing new chemistries, market-changing technologies and customer driven solutions at numerous technology centers located in the Americas, Europe and the Asia Pacific region. Research and development costs are expensed as they are incurred and totaled $110 million in fiscal 2015, $114 million in 2014 and $142 million in 2013. These amounts include impairment charges of $11 million, $13 million and $41 million during fiscal 2015, 2014 and 2013, respectively, related to certain in-process research and development assets associated with the acquisition of ISP. For additional information regarding these impairment charges, see Note H of Notes to Consolidated Financial Statements in this annual report on Form 10-K.

Seasonality

Ashland's business may vary due to seasonality. Ashland's business units typically experience stronger demand during warmer weather months, which generally occur during Ashland's third and fourth quarters.

Forward-Looking Statements

This annual report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements are not historical facts and generally are identified by words such as "anticipates," "believes," "estimates," "expects," "is likely," "predicts," "projects," "forecasts," "may," "will," "should," and "intends" and the negative of these words or other comparable terminology. Although Ashland believes that its expectations are based on reasonable assumptions, such expectations are subject to risks and uncertainties that are difficult to predict and may be beyond Ashland's control. As a result, Ashland cannot assure that the expectations contained in such statements will be achieved. Important factors that could cause actual results to differ materially from those contained in such statements are discussed under "Use of estimates, risks and uncertainties" in Note A of Notes to Consolidated Financial Statements in this annual report on Form 10-K. For a discussion of other factors and risks that could affect Ashland's expectations and operations, see "Item 1A. Risk Factors" in this annual report on Form 10-K.

ITEM 1A. RISK FACTORS

The following discussion of "risk factors" identifies the most significant factors that may adversely affect Ashland's business, operations, financial position or future financial performance. This information should be read in conjunction with Management's Discussion and Analysis and the consolidated financial statements and related notes incorporated by reference into this annual report on Form 10-K. The following discussion of risks is designed to highlight what Ashland believes are important factors to consider when evaluating its expectations. These factors could cause future results to differ from those in forward-looking statements and from historical trends.

Ashland has set aggressive growth goals for its businesses, including increasing sales, cash flow and margins, in order to achieve its long term strategic objectives. Ashland's successful execution of its growth strategies and business plans to facilitate that growth involves a number of risks.

Ashland has set aggressive growth goals for its chemicals and Valvoline businesses in order to meet long term strategic objectives and improve shareholder value. Ashland's failure to meet one or more of these goals or objectives would negatively impact Ashland's potential value and the businesses. One of the most important risks is that Ashland might fail to adequately execute its business and growth plans. Aspects of that risk include changes to global economic environment, changes to the competitive landscape, attraction and retention of skilled employees, the potential failure of product innovation plans, failure to comply with existing or new regulatory schemes, failure to maintain a competitive cost structure and other risks outlined in greater detail in this Item 1A.

Ashland's plan to separate into two independent, publicly traded companies is subject to various risks and uncertainties and may not be completed in accordance with the expected plans or anticipated timeline, or at all, and will involve significant time and expense, any of which could negatively impact our businesses.

On September 22, 2015, Ashland announced plans to separate its Valvoline business from its Specialty Ingredients and Performance Materials businesses in a structure that is expected to be tax free for Ashland shareholders. The separation is intended to be completed as soon as practicable, but will take no less than a year from the date of the announcement of the planned separation. The process of finalizing the transaction structure is underway. Once the separation structure is determined, the separation is subject to final approval from Ashland's board of directors. In addition, other unanticipated developments, including changes to the competitive environment for Valvoline's or new Ashland's respective markets, possible delays in obtaining or failure to obtain

tax opinions, regulatory or other approvals or clearances to approve or facilitate the separation, uncertainty in financial markets and other challenges in executing the separation as planned, could delay or prevent the separation, or cause it to occur on terms or conditions that are different or less favorable than expected.

Ashland expects that the process of completing the proposed separation will be time-consuming and involve significant costs and expenses, which may be significantly higher than those currently anticipated and may not yield a discernible benefit if the separation is not completed. Also, the time and energy required from Ashland's senior management and other employees to plan and execute the separation may lead to increased costs, increased expenses, negative effects on relationships with business partners, suppliers, and customers, disruptions in operations and ultimately harm its businesses. Ashland may also experience difficulty attracting, retaining and motivating employees during the pendency of the separation, which could also harm its businesses.

If the separation is completed, there is a further risk that the sum of the value of the two independent, publicly traded companies will be less than the value of Ashland before the separation. There is also a risk that the completed separation will not meet all of the intended financial, strategic, and operational benefits that were the impetus for the decision to separate the company.

Ashland's success depends upon its ability to attract and retain key employees and the identification and development of talent to succeed senior management.

Ashland's success depends on its ability to attract and retain key personnel, and Ashland relies heavily on its management team. The inability to recruit and retain key personnel or the unexpected loss of key personnel may adversely affect Ashland's operations. Also, a substantial portion of Ashland's U.S.-based employees will be retirement-eligible within the next five years. That, combined with the relatively small number of middle tier managers with substantial experience in place to replace this group of retirement eligible employees, increases the potential negative impact of the risk that key employees could leave the Company. This risk of unwanted employee turnover also is substantial in positions that require certain technical expertise and geographically in developing markets which Ashland has targeted for growth, especially in Asia, South America and Eastern Europe. This risk is further enhanced by the planned separation of Ashland into two publicly traded companies announced on September 22, 2015. In addition, because of its reliance on its management team, Ashland's future success depends, in part, on its ability to identify and develop talent to succeed its senior management and other key positions throughout the organization. If Ashland fails to identify and develop successors, the company is at risk of being harmed by the departures of these key employees.

Ashland faces competition from other companies, which places downward pressure on prices and margins and may adversely affect Ashland's businesses and results of operations.

Ashland operates in highly competitive markets, competing against a number of domestic and foreign companies. Competition is based on several key criteria, including product performance and quality, product price, product availability and security of supply, responsiveness of product development in cooperation with customers and customer service, as well as the ability to bring innovative products or services to the marketplace. Certain key competitors are significantly larger than Ashland and have greater financial resources, leading to greater operating and financial flexibility. As a result, these competitors may be better able to withstand changes in conditions within the relevant industry, changes in the prices of raw materials and energy and changes in general economic conditions. In addition, competitors' pricing decisions could compel Ashland to decrease its prices, which could negatively affect its margins and profitability. Additional competition in markets served by Ashland could adversely affect margins and profitability and could lead to a reduction in market share. Also, Ashland competes in certain markets that are declining and has targeted other markets for growth opportunities. If Ashland's strategies for dealing with declining markets and leveraging opportunity markets are not successful, its results of operations could be negatively affected.

Ashland's business exposes it to potential product liability claims and recalls, which could adversely affect its financial condition and performance.

The development, manufacture and sale of specialty chemical and other products by Ashland, including products produced for the food, beverage, personal care, pharmaceutical and nutritional supplement industries, involve an inherent risk of exposure to product liability claims, product recalls, product seizures and related adverse publicity. A product liability claim or judgment against Ashland could also result in substantial and unexpected expenditures, affect consumer or customer confidence in its products, and divert management's attention from other responsibilities. Although Ashland maintains product liability insurance, there can be no assurance that this type or the level of coverage is adequate or that Ashland will be able to continue to maintain its existing insurance or obtain comparable insurance at a reasonable cost, if at all. A product recall or a partially or completely uninsured product liability judgment against Ashland could have a material adverse effect on its reputation, results of operations and financial condition.

Failure to develop and market new products and production technologies could impact Ashland's competitive position and have an adverse effect on its businesses and results of operations.

The specialty chemical industry is subject to periodic technological change and ongoing product improvements. In order to maintain margins and remain competitive, Ashland must successfully develop and introduce new products or improvements that

appeal to its customers and ultimately to global consumers. Ashland plans to grow earnings, in part, by focusing on developing markets and solutions to meet increasing demand in those markets, including demand for personal care and pharmaceutical products which are subject to lengthy regulatory approval processes. Ashland's efforts to respond to changes in consumer demand in a timely and cost-efficient manner to drive growth could be adversely affected by difficulties or delays in product development, including the inability to identify viable new products, successfully complete research and development, obtain regulatory approvals, obtain intellectual property protection or gain market acceptance of new products. Due to the lengthy development process, technological challenges and intense competition, there can be no assurance that any of the products Ashland is currently developing, or could develop in the future, will achieve substantial commercial success.

The impact of changing laws or regulations or the manner of interpretation or enforcement of existing rules could adversely impact Ashland's financial performance and restrict its ability to operate its business or execute its strategies.

New laws or regulations, or changes in existing laws or regulations or the manner of their interpretation or enforcement, could increase Ashland's cost of doing business and restrict its ability to operate its business or execute its strategies. This includes, among other things, the possible taxation under U.S. law of certain income from foreign operations, the possible taxation under foreign laws of certain income Ashland reports in other jurisdictions, regulations related to the protection of private information of Ashland's employees and customers, regulations issued by the U.S. Food and Drug Administration (and analogous non-U.S. agencies) affecting Ashland and its customers, compliance with The U.S. Foreign Corrupt Practices Act (and analogous non-U.S. laws) and the European Union's Registration, Authorisation and Restriction of Chemicals (REACH) regulation (and analogous non-EU initiatives), and costs associated with complying with the Patient Protection and Affordable Care Act of 2010 and the regulations promulgated thereunder. In addition, compliance with laws and regulations is complicated by Ashland's substantial and growing global footprint, which will require significant and additional resources to comprehend and ensure compliance with applicable laws in the more than one hundred countries where Ashland conducts business.

Ashland's substantial global operations subject it to risks of doing business in foreign countries, which could adversely affect its business, financial condition and results of operations.

Approximately one half of Ashland's net sales for fiscal 2016 are expected to be to customers outside of North America. Ashland expects sales from international markets to continue to represent an even larger portion of the Company's sales in the future. Also, a significant portion of Ashland's manufacturing capacity is located outside of the United States. Accordingly, Ashland's business is subject to risks related to the differing legal, political, cultural, social and regulatory requirements and economic conditions of many jurisdictions.

The global nature of Ashland's business presents difficulties in hiring and maintaining a workforce in certain countries. Fluctuations in exchange rates may affect product demand and may adversely affect the profitability in U.S. dollars of products and services provided in foreign countries. In addition, foreign countries may impose additional withholding taxes or otherwise tax Ashland's foreign income, or adopt other restrictions on foreign trade or investment, including currency exchange controls. The imposition of tariffs is also a risk that could impair Ashland's financial performance.

Certain legal and political risks are also inherent in the operation of a company with Ashland's global scope. For example, it may be more difficult for Ashland to enforce its agreements or collect receivables through foreign legal systems. There is a risk that foreign governments may nationalize private enterprises in certain countries where Ashland operates. In certain countries or regions, terrorist activities and the response to such activities may threaten Ashland's operations more than in those in the United States. In Europe, the effect of economic sanctions imposed on Russia and/or Russia's reaction to the sanctions could adversely impact Ashland's performance and results of operations. Social and cultural norms in certain countries may not support compliance with Ashland's corporate policies including those that require compliance with substantive laws and regulations. Also, changes in general economic and political conditions in countries where Ashland operates, particularly in Europe, the Middle East and emerging markets, are a risk to Ashland's financial performance.

As Ashland continues to operate its business globally, its success will depend, in part, on its ability to anticipate and effectively manage these and other related risks. There can be no assurance that the consequences of these and other factors relating to its multinational operations will not have an adverse effect on Ashland's business, financial condition or results of operations.

The competitive nature of Ashland's markets may delay or prevent the Company from passing increases in raw materials or energy costs on to its customers. In addition, certain of Ashland's suppliers may be unable to deliver products or raw materials or may withdraw from contractual arrangements. The occurrence of either event could adversely affect Ashland's results of operations.

Rising and volatile raw material prices, especially those of hydrocarbon derivatives, cotton linters or wood pulp, may negatively impact Ashland's costs, results of operations and the valuation of its inventory. Similarly, energy costs are a significant component of certain of Ashland's product costs. Ashland is not always able to raise prices in response to such increased costs, and its ability

to pass on the costs of such price increases is dependent upon market conditions. Likewise, reductions in the valuation of Ashland's inventory due to market volatility may not be recovered and could result in losses.

Ashland purchases certain products and raw materials from suppliers, often pursuant to written supply contracts. If those suppliers are unable to meet Ashland's orders in a timely manner or choose to terminate or otherwise avoid contractual arrangements, Ashland may not be able to make alternative supply arrangements. Also, domestic and global government regulations related to the manufacture or transport of certain raw materials may impede Ashland's ability to obtain those raw materials on commercially reasonable terms. If Ashland is unable to obtain and retain qualified suppliers under commercially acceptable terms, its ability to manufacture and deliver products in a timely, competitive and profitable manner or grow its business successfully could be adversely affected.

Adverse developments in the global economy and potential disruptions of financial markets could negatively impact Ashland's customers and suppliers, and therefore have a negative impact on Ashland's results of operations.

A global or regional economic downturn may reduce customer demand or inhibit Ashland's ability to produce and sell products. Ashland's business and operating results are sensitive to global and regional economic downturns, credit market tightness, declining consumer and business confidence, fluctuating commodity prices, volatile exchange rates, changes in interest rates, sovereign debt defaults and other challenges, including those related to international sanctions and acts of aggression or threatened aggression that can affect the global economy. In the event of adverse developments or stagnation in the economy or financial markets, Ashland's customers may experience deterioration of their businesses, reduced demand for their products, cash flow shortages and difficulty obtaining financing. As a result, existing or potential customers might delay or cancel plans to purchase products and may not be able to fulfill their obligations to Ashland in a timely fashion. Further, suppliers may experience similar conditions, which could impact their ability to fulfill their obligations to Ashland. A weakening or reversal of the current economic recovery in the global economy or a substantial part of it could negatively impact Ashland's business, results of operations, financial condition and ability to grow.

Ashland uses information technology (IT) systems to conduct business and these IT systems are at risk from cyber security threats.

The nature of our businesses, the markets we serve, and geographic profile of our operations make Ashland a target of cyber security threats. Despite steps Ashland takes to mitigate or eliminate them, cyber security threats to our systems are increasing and becoming more advanced and could occur as a result of the activity of hackers, employee error or employee misconduct. A breach of our IT systems could lead to the loss and destruction of trade secrets, confidential information, proprietary data, intellectual property, customer and supplier data, and employee personal information, and could disrupt business operations which could adversely affect Ashland's relationships with business partners and harm our brands, reputation, and financial results.

Ashland may not be able to effectively protect or enforce its intellectual property rights.

Ashland relies on the patent, trademark, trade secret and copyright laws of the United States and other countries to protect its intellectual property rights. The laws of some countries may not protect Ashland's intellectual property rights to the same extent as the laws of the United States. Failure of foreign countries to have laws to protect Ashland's intellectual property rights or an inability to effectively enforce such rights in foreign countries could result in the loss of valuable proprietary information, which could have an adverse effect on Ashland's business and results of operations.

Even in circumstances where Ashland has a patent on certain technologies, such patents may not provide meaningful protection against competitors or against competing technologies. In addition, any patent applications submitted by Ashland may not result in an issued patent. There can be no assurance that Ashland's intellectual property rights will not be challenged, invalidated, circumvented or rendered unenforceable. Ashland could also face claims from third parties alleging that Ashland's products or processes infringe on their proprietary rights. If Ashland is found liable for infringement, it could be responsible for significant damages, prohibited from using certain products or processes or required to modify certain products and processes. Any such infringement liability could adversely affect Ashland's product and service offerings, profitability and results of operations.

Ashland also has substantial intellectual property associated with its know-how and trade secrets that are not protected by patent or copyright laws. Ashland protects these rights by entering into confidentiality and non-disclosure agreements with most of its employees and with third parties. There can be no assurance that such agreements will not be breached or that Ashland will be able to effectively enforce them. In addition Ashland's trade secrets and know how may be improperly obtained by other means, such as a breach of Ashland's information technologies security systems or direct theft. Any unauthorized disclosure of any of Ashland's material know-how or trade secrets could adversely affect Ashland's business and results of operations.

Business disruptions from natural, operational and other catastrophic risks could seriously harm Ashland's operations and financial performance. In addition, a catastrophic event at one of Ashland's facilities or involving its products or employees could lead to liabilities that could further impair its operations and financial performance.

Business disruptions, including those related to operating hazards inherent with the production of chemicals, natural disasters, severe weather conditions, supply or logistics disruptions, increasing costs for energy, temporary plant and/or power outages, information technology systems and network disruptions, cyber-security breach, terrorist attacks, armed conflict, war, pandemic diseases, fires, floods or other catastrophic events, could seriously harm Ashland's operations, as well as the operations of its customers and suppliers, and may adversely impact Ashland's financial performance. Although it is impossible to predict the occurrence or consequences of any such events, they could result in reduced demand for Ashland's products, make it difficult or impossible for Ashland to manufacture its products or deliver products and services to its customers or to receive raw materials from suppliers, or create delays and inefficiencies in the supply chain. In addition to leading to a serious disruption of Ashland's businesses, a catastrophic event at one of our facilities or involving our products or employees could lead to substantial legal liability to or claims by parties allegedly harmed by the event.

While Ashland maintains business continuity plans that are intended to allow it to continue operations or mitigate the effects of events that could disrupt its business, Ashland cannot provide assurances that its plans would fully protect it from all such events. In addition, insurance maintained by Ashland to protect against property damage, loss of business and other related consequences resulting from catastrophic events is subject to coverage limitations, depending on the nature of the risk insured. This insurance may not be sufficient to cover all of Ashland's damages or damages to others in the event of a catastrophe. In addition, insurance related to these types of risks may not be available now or, if available, may not be available in the future at commercially reasonable rates.

Ashland has incurred, and will continue to incur, substantial costs as a result of environmental, health and safety, and hazardous substances liabilities and related compliance requirements. These costs could adversely impact Ashland's cash flow, and, to the extent they exceed Ashland's established reserves for these liabilities, its results of operations.

Ashland is subject to extensive federal, state, local and foreign laws, regulations, rules and ordinances relating to pollution, protection of the environment and human health and safety, and the generation, storage, handling, treatment, disposal and remediation of hazardous substances and waste materials. Ashland has incurred, and will continue to incur, significant costs and capital expenditures to comply with these laws and regulations.

Environmental, health and safety regulations change frequently, and such regulations and their enforcement have tended to become more stringent over time. Accordingly, changes in environmental, health and safety laws and regulations and the enforcement of such laws and regulations could interrupt Ashland's operations, require modifications to its facilities or cause Ashland to incur significant liabilities, costs or losses that could adversely affect its profitability. Actual or alleged violations of environmental, health or safety laws and regulations could result in restrictions or prohibitions on plant operations as well as substantial damages, penalties, fines, civil or criminal sanctions and remediation costs. In addition, under some environmental laws, Ashland may be strictly liable and/or jointly and severally liable for environmental damages and penalties.

Ashland is also subject to various federal, state, local and foreign environmental laws and regulations that require environmental assessment or remediation efforts (collectively, environmental remediation) at multiple locations. Ashland uses engineering studies, historical experience and other factors to identify and evaluate remediation alternatives and their related costs in determining the estimated reserves for environmental remediation. Environmental remediation reserves are subject to numerous inherent uncertainties that affect Ashland's ability to estimate its share of the applicable costs. Such uncertainties involve the nature and extent of contamination at each site, the extent of required cleanup efforts under existing environmental regulations, widely varying costs of alternate cleanup methods, changes in environmental regulations, the potential effect of continuing improvements in remediation technology and the number and financial strength of other potentially responsible parties at multiparty sites. As a result, Ashland's actual costs for environmental remediation could affect Ashland's cash flow and, to the extent costs exceed established reserves for those liabilities, its results of operations.

Ashland is responsible for, and has financial exposure to, liabilities from pending and threatened claims, including those alleging personal injury caused by exposure to asbestos, which could adversely impact Ashland's results of operations and cash flow.

There are various claims, lawsuits and administrative proceedings pending or threatened, including those alleging personal injury caused by exposure to asbestos, against Ashland and its current and former subsidiaries. Such actions are with respect to commercial matters, product liability, toxic tort liability and other matters that seek remedies or damages, some of which are for substantial amounts. While these actions are being contested, their outcome is not predictable. Ashland's results could be adversely affected by financial exposure to these liabilities. Insurance maintained by Ashland to protect against claims for damages alleged by third parties is subject to coverage limitations, depending on the nature of the risk insured. This insurance may not be sufficient to cover all of Ashland's liabilities to others. In addition, insurance related to these types of risks may not be available now or, if

available, may not be available in the future at commercially reasonable rates. Ashland's ability to recover from its insurers for asbestos liabilities could also have an adverse impact on its results of operations. Projecting future asbestos costs is subject to numerous variables that are extremely difficult to predict. In addition to the significant uncertainties surrounding the number of claims that might be received, other variables include the type and severity of the disease alleged by each claimant, the long latency period associated with asbestos exposure, dismissal rates, costs of medical treatment, the impact of bankruptcies of other companies that are co-defendants in claims, uncertainties surrounding the litigation process from jurisdiction to jurisdiction and from case to case, and the impact of potential changes in legislative or judicial standards. Furthermore, any predictions with respect to these variables are subject to even greater uncertainty as the projection period lengthens. In light of these inherent uncertainties, Ashland believes that its asbestos reserves represent the best estimate within a range of possible outcomes. As a part of the process to develop these estimates of future asbestos costs, a range of long-term cost models was developed. These models are based on national studies that predict the number of people likely to develop asbestos-related diseases and are heavily influenced by assumptions regarding long-term inflation rates for indemnity payments and legal defense costs, as well as other variables mentioned previously. Because of the inherent uncertainties in projecting future asbestos liabilities and establishing appropriate reserves, Ashland's actual asbestos costs could adversely affect its results of operations and, to the extent they exceed its reserves, could adversely affect its results of operations.

Ashland's pension and postretirement benefit plan obligations are currently underfunded, and Ashland may have to make significant cash payments to some or all of these plans, which would reduce the cash available for Ashland's businesses.

Ashland has underfunded obligations under its domestic and foreign pension and postretirement benefit plans. The funded status of Ashland's pension plans is dependent upon many factors, including returns on invested assets, the level of certain market interest rates and the discount rate used to determine pension obligations. Unfavorable returns on plan assets or unfavorable changes in applicable laws or regulations could materially change the timing and amount of required plan funding, which would reduce the cash available for Ashland's businesses. In addition, a decrease in the discount rate used to determine pension obligations could result in an increase in the valuation of pension obligations, which could affect the reported funding status of Ashland's pension plans and future contributions. Similarly, an increase in discount rates could increase the periodic pension cost in subsequent fiscal years.

Under the Employee Retirement Income Security Act of 1974 (ERISA), as amended, the Pension Benefit Guaranty Corporation (PBGC) has the authority to terminate an underfunded tax-qualified pension plan under limited circumstances. In the event Ashland's tax-qualified pension plans are terminated by the PBGC, Ashland could be liable to the PBGC for some portion of the underfunded amount.

Ashland's substantial indebtedness may adversely affect its business, results of operations and financial condition.

Ashland maintains a substantial amount of debt. Ashland's substantial indebtedness could adversely affect its business, results of operations and financial condition by, among other things:

- requiring Ashland to dedicate a substantial portion of its cash flow from operations to pay principal and interest on its debt, which would reduce the availability of Ashland's cash flow to fund working capital, capital expenditures, acquisitions, execution of its growth strategy and other general corporate purposes;
- limiting Ashland's ability to borrow additional amounts to fund working capital, capital expenditures, acquisitions, debt service requirements, execution of its growth strategy and other purposes;
- making Ashland more vulnerable to adverse changes in general economic, industry and regulatory conditions and in its business by limiting Ashland's flexibility in planning for, and making it more difficult for Ashland to react quickly to, changing conditions;
- placing Ashland at a competitive disadvantage compared with those of its competitors that have less debt and lower debt service requirements;
- making Ashland more vulnerable to increases in interest rates since some of its indebtedness is subject to variable rates of interest; and
- making it more difficult for Ashland to satisfy its financial obligations.

In addition, Ashland may not be able to generate sufficient cash flow from its operations to repay its indebtedness when it becomes due and to meet its other cash needs. If Ashland is not able to pay its debts as they become due, it could be in default under its credit facility or other indebtedness. Ashland might also be required to pursue one or more alternative strategies to repay indebtedness, such as selling assets, refinancing or restructuring its indebtedness or selling additional debt or equity securities. Ashland may not be able to refinance its debt or sell additional debt or equity securities or its assets on favorable terms, if at all, and if Ashland must sell its assets, it may negatively affect its ability to generate revenues.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Ashland's corporate headquarters is located in Covington, Kentucky. Principal offices of other major operations are located in Wilmington, Delaware (Specialty Ingredients); Bridgewater, New Jersey (Specialty Ingredients); Dublin, Ohio (Specialty Ingredients and Performance Materials); Lexington, Kentucky (Valvoline); and Barendrecht, the Netherlands; Shanghai, China; Hyderabad, India; Warsaw, Poland; and Schaffhausen, Switzerland (each of which are shared service centers of Ashland's business units). All of these office buildings are leased, except for portions of the Dublin, Ohio and the Lexington, Kentucky facilities that are owned. Principal manufacturing, marketing and other materially important physical properties of Ashland and its subsidiaries are described within the applicable business units under "Item 1" in this annual report on Form 10-K. All of Ashland's physical properties are owned or leased. Ashland believes its physical properties are suitable and adequate for the Company's business. Additional information concerning certain leases may be found in Note K of Notes to Consolidated Financial Statements in this annual report on Form 10-K.

ITEM 3. LEGAL PROCEEDINGS

The following is a description of Ashland's material legal proceedings.

Asbestos-Related Litigation

Ashland is subject to liabilities from claims alleging personal injury caused by exposure to asbestos. Such claims result primarily from indemnification obligations undertaken in 1990 in connection with the sale of Riley Stoker Corporation (Riley), a former subsidiary. Although Riley was neither a producer nor a manufacturer of asbestos, its industrial boilers contained some asbestos-containing components provided by other companies.

Hercules, a wholly-owned subsidiary of Ashland, is also subject to liabilities from asbestos-related personal injury lawsuits involving claims which typically arise from alleged exposure to asbestos fibers from resin encapsulated pipe and tank products which were sold by one of Hercules' former subsidiaries to a limited industrial market.

Ashland and Hercules are also defendants in lawsuits alleging exposure to asbestos at facilities formerly or presently owned or operated by Ashland or Hercules.

In October 2012, Ashland and Hercules initiated various arbitration proceedings against Underwriters at Lloyd's, certain London companies and/or Chartis (AIG) member companies seeking to enforce these insurers' contractual obligations to provide indemnity for asbestos liabilities and defense costs under existing coverage-in-place agreements. In addition, Ashland and Hercules initiated a lawsuit in Kentucky state court against certain Berkshire Hathaway entities (National Indemnity Company and Resolute Management, Inc.) on grounds that these Berkshire Hathaway entities wrongfully interfered with Underwriters' and Chartis' performance of their respective contractual obligations to provide asbestos coverage by directing the insurers to reduce and delay certain claim payments.

On January 13, 2015, Ashland and Hercules entered into a comprehensive settlement agreement related to certain insurance coverage for asbestos bodily injury claims with Underwriters at Lloyd's, certain London companies and Chartis (AIG) member companies, along with National Indemnity Company and Resolute Management, Inc., under which Ashland and Hercules received a total of $398 million. In exchange, all claims were released against these entities for past, present and future coverage obligations arising out of the asbestos coverage-in-place agreements that were the subject of the pending arbitration proceedings. In addition, as part of this settlement, Ashland and Hercules released all claims against National Indemnity Company and Resolute Management, Inc. in the Kentucky state court action. As a result, the arbitration proceedings and the Kentucky state court action have been terminated.

As a result of this settlement, during 2015, Ashland recorded an after-tax gain of $120 million within the discontinued operations caption of the Statements of Consolidated Comprehensive Income and a $249 million reduction in the asbestos insurance receivable balance, consisting of $227 million and $22 million for Ashland and Hercules, respectively, within the Condensed Consolidated Balance Sheets. See Note N of the Notes to Condensed Consolidated Financial Statements in this annual report on Form 10-K for further information.

In addition, Ashland placed $335 million of the settlement funds received into a renewable annual trust restricted for the purpose of paying for ongoing and future litigation defense and claim settlement costs incurred in conjunction with asbestos claims.

For additional detailed information regarding liabilities arising from asbestos-related litigation, see "Management's Discussion and Analysis - Critical Accounting Policies - Asbestos Litigation" and Note N of Notes to Consolidated Financial Statements in this annual report on Form 10-K.

Environmental Proceedings

(a) CERCLA and Similar State Law Sites - Under the Comprehensive Environmental Response, Compensation and Liability Act of 1980 and similar state laws, Ashland and its subsidiaries may be subject to joint and several liability for cleanup costs in connection with alleged releases of hazardous substances at sites where it has been identified as a "potentially responsible party" (PRP). As of September 30, 2015, Ashland and its subsidiaries have been identified as a PRP by U.S. federal and state authorities, or by private parties seeking contribution, for the cost of environmental investigation and/or cleanup at 85 waste treatment or disposal sites. These sites are currently subject to ongoing investigation and remedial activities, overseen by the United States Environmental Protection Agency (USEPA) or a state agency, in which Ashland or its subsidiaries are typically participating as a member of a PRP group. Generally, the type of relief sought includes remediation of contaminated soil and/or groundwater, reimbursement for past costs of site cleanup and administrative oversight and/or long-term monitoring of environmental conditions at the sites. The ultimate costs are not predictable with assurance.

(b) Hattiesburg, Mississippi Resource Conservation and Recovery Act Matter - In November 2008, the Mississippi Department of Environmental Quality (MDEQ) issued a Notice of Violation to Hercules' now-closed Hattiesburg, Mississippi manufacturing facility alleging that a process water impoundment basin at the facility had been operated as a hazardous waste storage and treatment facility without a permit in violation of the Resource Conservation and Recovery Act. In May 2011, the USEPA issued an inspection report from a September 2010 inspection with allegations similar to those of the MDEQ and promulgated an information request. Ashland has been working with the MDEQ and USEPA to settle this matter in the context of the shutdown and ongoing remediation of the Hattiesburg facility. The USEPA proposed a settlement penalty in excess of $100,000. While it is reasonable to believe that this matter will involve a penalty from the MDEQ and/or the USEPA exceeding $100,000, the potential penalty with respect to this enforcement matter should not be material to Ashland.

(c) Lower Passaic River, New Jersey Matters - Ashland, through two formerly owned facilities, and ISP, through a now-closed facility, have been identified as PRPs, along with approximately 70 other companies (the Cooperating Parties Group or the CPG), in a May 2007 Administrative Order of Consent (AOC) with the USEPA. The parties are required to perform a remedial investigation and feasibility study (RI/FS) of the entire 17 miles of the Passaic River. In June 2007, the EPA separately commenced a Focused Feasibility Study (FFS) as an interim measure. In accordance with the 2007 AOC, in June 2012 the CPG voluntarily entered into another AOC for an interim removal action focused solely at mile 10.9 of the Passaic River. The allocations for the 2007 AOC and the 2012 removal action are based on interim allocations, are immaterial and have been accrued. In April 2014, the EPA released the FFS. The CPG submitted the Draft RI/FS Report on April 30, 2015. The EPA is expected to release the FFS Record of Decision for the lower 8 miles by December 31, 2015. Based on current knowledge and proceedings, Ashland does not believe the outcome of these proceedings or the release of the FFS Record of Decision will have a material adverse impact on its business and financial operations; however, there are a number of contingencies in the future that could possibly have a material impact including adverse rulings or verdicts, allocation proceedings and related orders.

(d) Zwijndrecht Plant Matter - Between August 2012 and January 2014, Dutch environmental authorities have found several violations of a waste water discharge permit by Ashland Industries Nederland B.V., as owner of the manufacturing site at Zwijndrecht, The Netherlands. As a result, administrative penalties and sanctions totaling €350,000 were paid during calendar years 2013 and 2014. In addition, Dutch authorities announced prosecution with regards to some permit violations. Ashland initiated a settlement proposal and is awaiting a response to the proposal. While it is reasonable to believe that this matter will involve an additional penalty exceeding $100,000, the potential liability with respect to this matter should not be material to Ashland.

For additional information regarding environmental matters and reserves, see Note N of Notes to Consolidated Financial Statements in this annual report on Form 10-K.

Other Pending Legal Proceedings

In addition to the matters described above, there are other various claims, lawsuits and administrative proceedings pending or threatened against Ashland and its current and former subsidiaries. Such actions are with respect to commercial matters, product liability, toxic tort liability and other environmental matters which seek remedies or damages, some of which are for substantial amounts. While Ashland cannot predict with certainty the outcome of such actions, it believes that adequate reserves have been recorded and losses already recognized with respect to such actions were immaterial as of September 30, 2015. There is a reasonable possibility that a loss exceeding amounts already recognized may be incurred related to these actions; however, Ashland believes that such potential losses were immaterial as of September 30, 2015.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM X. EXECUTIVE OFFICERS OF ASHLAND

The following is a list of Ashland's current executive officers, their ages and their positions and offices during the last five years (listed alphabetically after the current members of Ashland's Executive Committee).

WILLIAM A. WULFSOHN (age 53) is Chairman and Chief Executive Officer of Ashland since January 1, 2015. Prior to joining Ashland, Mr. Wulfsohn served as President and Chief Executive Officer of Carpenter Technology Corp., a manufacturer of stainless steel, titanium, and other specialty metals and engineered products, from July 2010 to November 2014. Mr. Wulfsohn also served as a Director for Carpenter Technology Corp. from April 2009 to November 2014.

J. KEVIN WILLIS (age 50) is Senior Vice President and Chief Financial Officer of Ashland and has served in such capacities since May 2013. Mr. Willis served as Vice President of Finance and Controller for the Specialty Ingredients business unit from August 2011 until May 2013 and Vice President of Finance and Treasurer from 2007 to 2011.

PETER J. GANZ (age 53) is Senior Vice President, General Counsel, Secretary and Chief Compliance Officer of Ashland and has served as Senior Vice President, General Counsel and Chief Compliance Officer since July 2011 and Secretary since November 2012. Prior to joining Ashland, Mr. Ganz served as a partner with Sedgwick LLP, an international law firm, and as Executive Vice President, General Counsel and Secretary of Foster Wheeler AG, a global engineering and construction contractor and power equipment supplier.

LUIS FERNANDEZ-MORENO (age 53) is Senior Vice President of Ashland and President, Chemicals Group since April 2015. He previously served as Senior Vice President of Ashland and President, Ashland Specialty Ingredients from October 2013 until April 2015. Prior to that, Mr. Fernandez-Moreno served as Vice President of Ashland and President of Water Technologies from November 2012 until October 2013. During the past five years, he has served as Executive Vice President of Arch Chemicals, Inc., a global biocides company, where he was responsible for the wood protection and HTH water products businesses.

SAMUEL J. MITCHELL, JR. (age 54) is Senior Vice President of Ashland and President,Valvoline and has served in such capacities since 2011 and 2002, respectively. During the past five years, he has also served as Vice President of Ashland.

GREGORY W. ELLIOTT (age 54) joined Ashland on November 9, 2015 as its Vice President and Chief Human Resources and Communications Officer. Since 2008, Mr. Elliott served as the Senior Vice President, Human Resources and Administration of Navistar, Inc., a global manufacturer of commercial and military trucks, proprietary diesel engines and buses.

J. WILLIAM HEITMAN (age 61) is Vice President and Controller of Ashland and has served in such capacities since 2008.

KEITH C. SILVERMAN (age 48) is Vice President, Environmental, Health, Safety and Regulatory Compliance and has served in such capacities since February 2014. He previously served as Vice President, Environmental, Health, Safety and Product Regulatory from June 2012 until January 2014. Prior to joining Ashland, he spent a number of years at Merck & Co., Inc., a pharmaceutical company, where he held various positions of increasing responsibility in research and development as well as in global safety and the environment.

ANNE T. SCHUMANN (age 55) is Vice President and Chief Information and Administrative Services Officer of Ashland and has served in such capacities since 2008 and 2009, respectively.

Each executive officer is elected by the Board of Directors of Ashland to a term of one year, or until a successor is duly elected, at the annual meeting of the Board of Directors, except in those instances where the officer is elected other than at an annual meeting of the Board of Directors, in which case his or her tenure will expire at the next annual meeting of the Board of Directors unless the officer is re-elected.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

See Quarterly Financial Information on page F-56 for information relating to market price and dividends of Ashland's Common Stock.

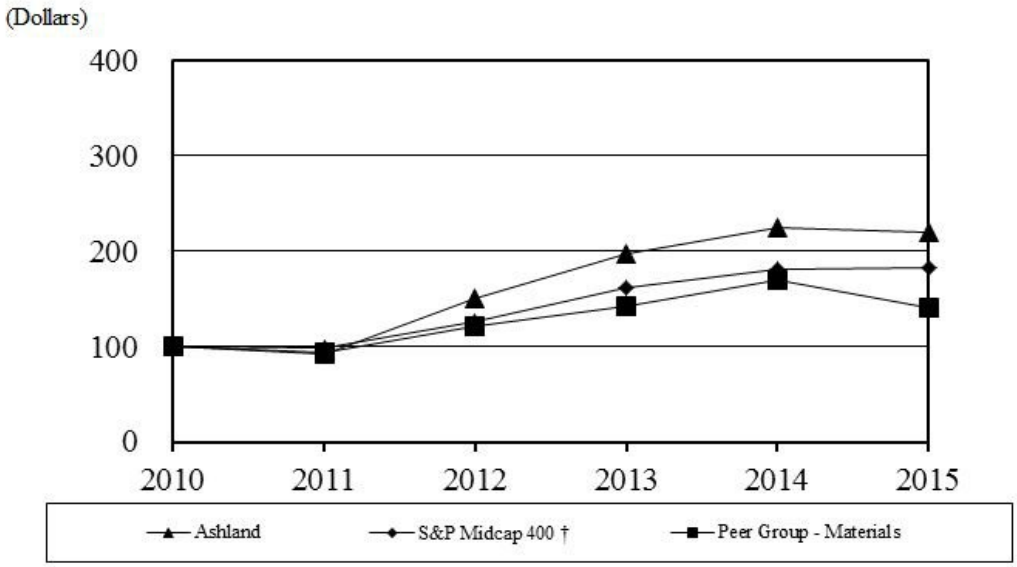
At October 31, 2015, there were approximately 13,000 holders of record of Ashland's Common Stock. Ashland Common Stock is listed on the New York Stock Exchange (NYSE) (ticker symbol ASH) and has trading privileges on NASDAQ.

There were no sales of unregistered securities required to be reported under Item 5 of Form 10-K.

FIVE-YEAR TOTAL RETURN PERFORMANCE GRAPH

The following graph compares Ashland's five-year cumulative total shareholder return with the cumulative total return of the S&P MidCap 400† index and one peer group of companies. Ashland is listed in the S&P MidCap 400† index. The cumulative total shareholder return assumes the reinvestment of dividends.

COMPARISON OF FIVE-YEAR CUMULATIVE TOTAL RETURN
ASHLAND, S&P MIDCAP 400† INDEX AND PEER GROUP



	2010	2011	2012	2013	2014	2015
Ashland	100	92	150	197	225	220
S&P MidCap 400†	100	99	127	162	181	183
Peer Group - Materials	100	93	122	143	170	140

The peer group consists of the following industry indices:

- *Peer Group – Materials:* S&P 500† Materials (large-cap) and S&P MidCap 400† Materials. As of September 30, 2015, this peer group consisted of 59 companies.

Purchase of Company Common Stock

Share repurchase activity during the three months ended September 30, 2015 was as follows:

Q4 Fiscal Periods	Total Number of Shares Purchased		Average Price Paid per Share, including commission	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (in millions) (a)
July 1, 2015 to July 31, 2015:					$ 1,000
2014 ASR Agreements	563,905	(b)	$ 116.33	563,905	
2015 ASR Agreements	302,315	(b)	125.22	302,315	
Employee tax withholdings	6,447	(c)	119.60	—	
August 1, 2015 to August 31, 2015	448	(c)	108.47	—	1,000
September 1, 2015 to September 30, 2015	2,629	(c)	105.34	—	1,000
Total.....	875,744			866,220	$ 1,000

(a) On April 28, 2015, Ashland's Board of Directors approved a $1 billion share repurchase authorization that expires December 31, 2017 and allows for shares to be repurchased in privately negotiated and/or open market transactions, including under plans complying with Rule 10b5-1 of the Exchange Act. The $1 billion represents the remaining amount available for share repurchase as of September 30, 2015. On November 17, 2015, Ashland entered into an uncollared accelerated share repurchase agreement (the November 2015 ASR Agreement) with Goldman Sachs & Co. (Goldman Sachs) to repurchase an aggregate of $500 million of Ashland's common stock. Under the November 2015 ASR Agreement, Ashland has agreed to repurchase an aggregate of $500 million of its common stock from Goldman Sachs, with an initial delivery of approximately 3.9 million shares. The November 2015 ASR Agreement is scheduled to terminate no later than May 2016 but may be terminated early in certain circumstances, in whole or in part. Goldman Sachs may be required to deliver additional shares of common stock to Ashland, or under certain circumstances, Ashland may be required to deliver shares of common stock or to make a cash payment, at its election, to Goldman Sachs.

(b) In August 2014, the Company entered into an accelerated share repurchase program with two financial institutions to purchase $750 million of the Company's common stock (the 2014 ASR Agreements). In exchange for an up-front payment totaling $750 million, the financial institutions initially delivered approximately 5.9 million shares of Ashland common stock. The 2014 ASR Agreements had a variable maturity, at the financial institutions' option, with a pricing period termination date of no later than June 30, 2015. In June 2015, the 2014 ASR Agreements terminated pursuant to their terms and the pricing period was closed. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $116.33 per share. Based on this settlement price, the final number of shares repurchased by Ashland that were to be delivered by the financial institutions was 6.4 million shares. Ashland received the additional 563,905 shares from the financial institutions in the September 2015 quarter to settle the difference between the initial share delivery and the total number of shares repurchased.

Additionally, in January 2015, the Company entered into accelerated share repurchase programs to purchase $269.6 million of the Company's common stock (the 2015 ASR Agreements). In exchange for an up-front payment totaling $269.6 million, the financial institutions initially delivered approximately 1.9 million shares of Ashland common stock. The 2015 ASR Agreements had a variable maturity, at the financial institutions' option, with a pricing period termination date of no later than July 31, 2015. In June 2015, the financial institutions exercised their early termination option under the 2015 ASR Agreements and the pricing period was closed. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $125.22 per share. Based on this settlement price, the final number of shares repurchased by Ashland that were to be delivered by the financial institutions under the 2015 ASR Agreements was 2.2 million shares. Ashland received the additional 302,315 shares from the financial institutions in the September 2015 quarter to settle the difference between the initial share delivery and the total number of shares repurchased. The average price paid by the Company for the shares delivered under the 2014 ASR Agreements and the 2015 ASR Agreements was $119.43.

(c) Shares withheld from employees to cover their withholding requirements for personal income taxes related to the vesting of restricted stock.

ITEM 6. SELECTED FINANCIAL DATA

See Five-Year Selected Financial Information on page F-57.

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

See Management's Discussion and Analysis of Financial Condition and Results of Operations on pages M-1 through M-39.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Quantitative and Qualitative Disclosures about Market Risk on page M-39.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The consolidated financial statements of Ashland presented in this annual report on Form 10-K are listed in the index on page F-1.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures – As of September 30, 2015, Ashland, under the supervision and with the participation of Ashland's management, including Ashland's Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of Ashland's disclosure controls and procedures as defined in Exchange Act Rules 13a-15(e) and 15d-15(e). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures were effective as of September 30, 2015.

Internal Control over Financial Reporting – See Management's Report on Internal Control Over Financial Reporting on page F-2 and the Reports of Independent Registered Public Accounting Firms on page F-3, F-4, and F-5.

Changes in Internal Control over Financial Reporting – There have been no changes in Ashland's internal control over financial reporting that occurred during the quarter ended September 30, 2015 that have materially affected, or are reasonably likely to materially affect, Ashland's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

There is hereby incorporated by reference the information to appear under the caption "Proposal One - Election of Directors for a One-Year Term" in Ashland's Proxy Statement, which will be filed with the SEC within 120 days after September 30, 2015. See also the list of Ashland's executive officers and related information under "Executive Officers of Ashland" in Part I - Item X in this annual report on Form 10-K.

There is hereby incorporated by reference the information to appear under the caption "Corporate Governance - Governance Principles" in Ashland's Proxy Statement.

There is hereby incorporated by reference the information to appear under the caption "Corporate Governance - Shareholder Nominations of Directors" in Ashland's Proxy Statement.

There is hereby incorporated by reference the information to appear under the caption “Audit Committee Report” regarding Ashland’s audit committee and audit committee financial experts, as defined under Item 407(d)(4) and (5) of Regulation S-K in Ashland’s Proxy Statement.

There is hereby incorporated by reference the information to appear under the caption "Corporate Governance - Section 16 (a) Beneficial Ownership Reporting Compliance" in Ashland's Proxy Statement.

ITEM 11. EXECUTIVE COMPENSATION

There is hereby incorporated by reference the information to appear under the captions “Compensation of Directors,” “Corporate Governance - Personnel and Compensation Committee Interlocks and Insider Participation,” “Executive Compensation,” “Compensation Discussion and Analysis,” and “Personnel and Compensation Committee Report on Executive Compensation” in Ashland’s Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

There is hereby incorporated by reference the information to appear under the captions “Ashland Common Stock Ownership of Certain Beneficial Owners,” and “Ashland Common Stock Ownership of Directors and Executive Officers of Ashland” in Ashland’s Proxy Statement.

The following table summarizes the equity compensation plans under which Ashland Common Stock may be issued as of September 30, 2015.

Plan Category	Equity Compensation Plan Information		
	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by security holders	830,851 (1)	$ 63.65 (2)	2,823,304 (3)
Equity compensation plans not approved by security holders	202,901 (4)	—	685,655 (5)
Total	1,033,752	$ 63.65 (2)	3,508,959

(1) This figure includes (a) 5,874 stock options outstanding under the Amended and Restated Ashland Inc. Incentive Plan ("Amended Plan") and (b) 102 stock options outstanding under the Hercules Incorporated Amended and Restated Long Term Incentive Compensation Plan. This figure also includes 2,972 net shares that could be issued under stock-settled SARs under the Amended Plan, 183,657 net shares that could be issued under stock-settled SARs under the 2006 Ashland Inc. Incentive Plan ("2006 Incentive Plan") and 222,055 net shares that could be issued under stock-settled SARs and 16,000 shares that could be issued under stock-settled restricted stock units under the Amended and Restated 2011 Ashland Inc. Incentive Plan ("2011 Incentive Plan"), based upon the closing price of Ashland Common Stock on the NYSE as of September 30, 2015 of $100.62. Additionally, this figure includes 151,088 restricted shares granted under the Amended Plan and deferred, 71,298 performance share units for the fiscal 2013-2015 performance period, 58,983 performance share units for the fiscal 2014-2016 performance period, and 68,592 performance share units for the fiscal 2015-2017 performance period, payable in Ashland Common Stock under the 2011 Incentive Plan, estimated assuming target performance is achieved. Also included in the figure are 31,680 shares to be issued under the pre-2005 Deferred Compensation Plan for Employees and 17,258 shares to be issued under the pre-2005 Deferred Compensation Plan for Non-Employee Directors, payable in Ashland Common Stock upon termination of employment or service with Ashland.

(2) The weighted-average exercise price excludes shares in Ashland Common Stock which may be distributed under the deferred compensation plans and the deferred restricted stock and performance share units which may be distributed under the 2011 Incentive Plan, as described in footnotes (1) and (4) in this table.

(3) This figure includes 2,414,128 shares available for issuance under the Amended and Restated 2015 Ashland Inc. Incentive Plan ("2015 Incentive Plan"), 144,789 shares available for issuance under the pre-2005 Deferred Compensation Plan for Employees and 264,387 shares available for issuance under the pre-2005 Deferred Compensation Plan for Non-Employee Directors. Under the 2015 Incentive Plan, full-value awards, which include all awards other than stock options and SARs, reduce the share reserve on a 2.75-to-1 basis.

(4) This figure includes 31,223 shares to be issued under the Deferred Compensation Plan for Employees (2005), which is described in the "Non-Qualified Deferred Compensation-Ashland Inc. Employees' Deferral Plan" section of Ashland's proxy statement, and 171,678 shares to be issued under the Deferred Compensation Plan for Non-Employee Directors (2005), which is described in the "Compensation of Directors-Annual Retainer" and "Compensation of Directors-Restricted Shares/Units" sections of Ashland's proxy statement, payable in Ashland Common Stock upon termination of employment or service with Ashland. Because these plans are not equity compensation plans as defined by the rules of the NYSE, neither plan required approval by Ashland's shareholders.

(5) This figure includes 382,741 shares available for issuance under the Deferred Compensation Plan for Employees (2005) and 302,914 shares available for issuance under the Deferred Compensation Plan for Non-Employee Directors (2005). Because these plans are not equity compensation plans as defined by the rules of the NYSE, neither plan required approval by Ashland's shareholders. Ashland also granted Mr. Wulfsohn, its Chief Executive Officer, an employment inducement award, in compliance with Rule 303A.08 of The New York Stock Exchange Listed Company Manual, consisting of a one-time grant of time-vested restricted stock in the amount of 50,000 shares ("2015 Inducement Award"). All shares under the 2015 Inducement Award have been granted, are no longer available for future issuance and are not included in this figure.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

There is hereby incorporated by reference the information to appear under the captions "Corporate Governance – Director Independence and Certain Relationships," "Corporate Governance - Related Person Transaction Policy," and "Audit Committee Report" in Ashland's Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

There is hereby incorporated by reference the information with respect to principal accounting fees and services to appear under the captions "Audit Committee Report" and "Proposal Two - Ratification of Independent Registered Public Accountants" in Ashland's Proxy Statement.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as part of this Report

(1) Financial Statements; and

(2) See Item 15(b) in this annual report on Form 10-K

The consolidated financial statements of Ashland presented in this annual report on Form 10-K are listed in the index on page F-1.

Schedules other than that listed above have been omitted because of the absence of the conditions under which they are required or because the information required is shown in the consolidated financial statements or the notes thereto. Separate financial statements of unconsolidated affiliates are omitted because each company does not constitute a significant subsidiary using the 20% tests when considered individually. Summarized financial information for all unconsolidated affiliates is disclosed in Note D of Notes to Consolidated Financial Statements.

(b) Documents required by Item 601 of Regulation S-K

2.1 – Stock and Asset Purchase Agreement, dated as of February 18, 2014, between Ashland Inc. and CD&R Seahawk Bidco, LLC (filed as Exhibit 2.1 to Ashland's Form 8-K filed on February 24, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

2.2 – Sale and Purchase Agreement related to the ASK Chemicals Group, dated April 8, 2014, among Ashland Inc., Ashland International Holdings, Inc., Clariant Produkte (Deutschland) GmbH, Clariant Corp., mertus 158. GmbH, Ascot US Bidco Inc. and Ascot UK Bidco Limited (filed as Exhibit 2.1 to Ashland's Form 8-K filed on April 14, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

3.1 – Fourth Restated Articles of Incorporation of Ashland Inc. (filed as Exhibit 3.2 to Ashland's Form 8-K filed on February 4, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

3.2 – By-laws of Ashland Inc., as amended and restated (filed as Exhibit 3.3 to Ashland's Form 8-K filed on February 4, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

4.1 – Ashland agrees to provide the SEC, upon request, copies of instruments defining the rights of holders of long-term debt of Ashland and all of its subsidiaries for which consolidated or unconsolidated financial statements are required to be filed with the SEC.

4.2 – Indenture, dated as of August 15, 1989, as amended and restated as of August 15, 1990, between Ashland Inc. and Citibank, N.A., as Trustee (filed as Exhibit 4.2 to Ashland's Form 10-K for the fiscal year ended September 30, 2008 (SEC File No. 001-32532), and incorporated herein by reference).

4.3 – Agreement of Resignation, Appointment and Acceptance, dated as of November 30, 2006, by and among Ashland Inc., Wilmington Trust Company (Wilmington) and Citibank, N.A. (Citibank) whereby Wilmington replaced Citibank as Trustee under the Indenture dated as of August 15, 1989, as amended and restated as of August 15, 1990, between Ashland Inc. and Citibank (filed as Exhibit 4 to Ashland's Form 10-Q for the quarter ended December 31, 2006 (SEC File No. 001-32532), and incorporated herein by reference).

4.4 – Indenture, dated May 27, 2009, by and among Ashland Inc., the Guarantors and U.S. Bank National Association (filed as Exhibit 4.1 to Ashland's Form 10-Q for the quarter ended June 30, 2009 (SEC File No. 001-32532), and incorporated herein by reference).

4.5 – Warrant Agreement dated July 27, 1999 between Hercules and The Chase Manhattan Bank, as warrant agent (filed as Exhibit 4.4 to Hercules' Form 8-K filed on July 28, 1999 (SEC File No. 001-00496), and incorporated herein by reference).

4.6 – Form of Series A Junior Subordinated Deferrable Interest Debentures (filed as Exhibit 4.5 to Hercules' Form 8-K filed on July 28, 1999 (SEC File No. 001-00496), and incorporated herein by reference).

4.7 – Form of CRESTS^{SM} Unit (filed as Exhibit 4.7 to Hercules' Form 8-K filed on July 28, 1999 (SEC File No. 001-00496), and incorporated herein by reference).

4.8 – Form of Warrant (filed as Exhibit 4.8 to Hercules' Form 8-K filed on July 28, 1999 (SEC File No. 001-00496), and incorporated herein by reference).

4.9 – Form of $100,000,000 6.6% Debenture due August 27, 2027 (filed as Exhibit 4.2 to Hercules' Form 8-K filed on July 30, 1997 (SEC File No. 001-00496), and incorporated herein by reference).

4.10 – Indenture, dated as of August 7, 2012, between Ashland Inc. and U.S. Bank N.A., as Trustee (filed as Exhibit 4.1 to Ashland's Form 8-K filed on September 21, 2012 (SEC File No. 001-32532), and incorporated herein by reference).

4.11 – First Supplemental Indenture, dated as of February 26, 2013, between Ashland Inc. and U.S. Bank National Association, as Trustee, in respect of the senior notes due 2022 (filed as Exhibit 4.11 to Ashland's Form 10-K for the fiscal year ended September 30, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

4.12 – Indenture, dated as of February 26, 2013, between Ashland Inc. and U.S. Bank National Association, as Trustee (filed as Exhibit 4.3 to Ashland's Form 8-K filed on February 27, 2013 (SEC File No. 001- 32532), and incorporated herein by reference).

4.13 – First Supplemental Indenture, dated as of February 26, 2013, between Ashland Inc. and U.S. Bank National Association, as Trustee, in respect of the senior notes due 2016, 2018 and 2043 (filed as Exhibit 4.4 to Ashland's Form 8-K filed on February 27, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

4.14 – Second Supplemental Indenture, dated as of March 14, 2013, between Ashland Inc. and U.S. Bank National Association, as Trustee, in respect of the senior notes due 2043 (filed as Exhibit 4.2 to Ashland's Form 8-K filed on March 18, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

The following Exhibits 10.1 through 10.43 are contracts or compensatory plans or arrangements or management contracts required to be filed as exhibits pursuant to Items 601(b)(10)(ii)(A) and 601(b)(10)(iii)(A) and (B) of Regulation S-K.

10.1 – Ashland Inc. Deferred Compensation Plan for Non-Employee Directors and Amendment No. 1 (filed as Exhibit 10.5 to Ashland's Form 10-Q for the quarter ended December 31, 2004 (SEC File No. 001-02918), and incorporated herein by reference).

10.2 – Ashland Inc. Deferred Compensation Plan and Amendment No. 1 (filed as Exhibit 10.3 to Ashland's Form 10-Q for the quarter ended December 31, 2004 (SEC File No. 001-02918), and incorporated herein by reference).

10.3 – Amended and Restated Ashland Inc. Deferred Compensation Plan for Employees (2005) (filed as Exhibit 10.3 to Ashland's Form 10-K for the fiscal year ended September 30, 2008 (SEC File No. 001-32532), and incorporated herein by reference).

10.4 – Amended and Restated Ashland Inc. Deferred Compensation Plan for Non-Employee Directors (2005) (filed as Exhibit 10.4 to Ashland's Form 10-K for the fiscal year ended September 30, 2008 (SEC File No. 001-32532), and incorporated herein by reference).

10.5 – Amended and Restated Ashland Inc. Supplemental Early Retirement Plan for Certain Employees (filed as Exhibit 10.5 to Ashland's Form 10-K for the fiscal year ended September 30, 2010 (SEC File No. 001-32532), and incorporated herein by reference).

10.6 – Amendment to the Ashland Inc. Supplemental Early Retirement Plan for Certain Employees (filed as Exhibit 10.10 to Ashland's Form 10-Q for the quarter ended June 30, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.7 – Amendment to the Amended and Restated Ashland Inc. Deferred Compensation Plan for Non-Employee Directors (2005) (filed as Exhibit 10.4 to Ashland's Form 10-Q for the quarter ended March 31, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.8 – Ashland Supplemental Defined Contribution Plan for Certain Employees (filed as Exhibit 10.3 to Ashland's Form 10-Q for the quarter ended March 31, 2011 (SEC File No. 001-32532), and incorporated herein by reference).

10.9 – Ashland Inc. Supplemental Defined Contribution Plan for Certain Employees effective January 1, 2015 (filed as Exhibit 10.1 to Ashland's Form 8-K filed on May 18, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.10 – Amended and Restated Ashland Inc. Nonqualified Excess Benefit Pension Plan (filed as Exhibit 10.6 to Ashland's Form 10-K for the fiscal year ended September 30, 2008 (SEC File No. 001-32532), and incorporated herein by reference).

10.11 – Hercules Incorporated Employee Pension Restoration Plan (filed as Exhibit 10.9 to Ashland's Form 10-K for the fiscal year ended September 30, 2010 (SEC File No. 001-32532), and incorporated herein by reference).

10.12 – Form of Chief Executive Officer Change in Control Agreement (filed as Exhibit 10.1 to Ashland's Form 8-K filed on January 7, 2009 (SEC File No. 001-32532), and incorporated herein by reference).

10.13 – Form of Executive Officer Change in Control Agreement, effective for agreements entered into after July 2009 (filed as Exhibit 10.11 to Ashland's Form 10-K for the fiscal year ended September 30, 2009 (SEC File No. 001-32532), and incorporated herein by reference) (Replaced in the first quarter of fiscal 2016).

10.14 – Form of Inducement Restricted Stock Award Agreement, between William A. Wulfsohn and Ashland (filed as Exhibit 4.3 to Ashland's Form S-8 filed on December 18, 2014 (SEC File No. 333-201053), and incorporated herein by reference).

10.15 – Form of Chief Executive Officer Change in Control Agreement (filed as Exhibit 10.3 to Ashland's Form 10-Q for the quarter ended December 31, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.16 – Form of Chief Executive Officer Change in Control Agreement (filed as Exhibit 10.1 to Ashland's Form 8-K filed on October 9, 2015 (SEC File No. 001-32532), and incorporated herein by reference) (Replaced in the first quarter of fiscal 2016).

10.17 – Form of Executive Officer Change in Control Agreement (filed as Exhibit 10.2 to Ashland's Form 8-K filed on October 9, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.18 – Ashland Inc. Severance Pay Plan (filed as Exhibit 10.1 to Ashland's Form 10-Q for the quarter ended June 30, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

10.19 – Form of Indemnification Agreement between Ashland and members of its Board of Directors (filed as Exhibit 10.10 to Ashland's annual report on Form 10-K for fiscal year ended September 30, 2005 (SEC File No. 001-32532), and incorporated herein by reference).

10.20 – Amended and Restated Ashland Inc. Incentive Plan (filed as Exhibit 10.17 to Ashland's Form 10-K for the fiscal year ended September 30, 2009 (SEC File No. 001-32532), and incorporated herein by reference).

10.21 – 2006 Ashland Inc. Incentive Plan (filed as Exhibit 10 to Ashland's Form 10-Q for the quarter ended December 31, 2005 (SEC File No. 001-32532), and incorporated herein by reference).

10.22 – Amended and Restated 2011 Ashland Inc. Incentive Plan (filed as Exhibit 10.1 to Ashland's Form 8-K filed on February 1, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

10.23 – Amended and Restated 2015 Ashland Inc. Incentive Plan (filed as Exhibit 10.1 to Ashland's Form 8-K filed on July 20, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.24 – Form of Stock Appreciation Rights Award Agreement under the Amended and Restated 2011 Ashland Inc. Incentive Plan (filed as Exhibit 10.16 to Ashland's Form 10-K for the fiscal year ended September 30, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.25 – Form of Performance Unit (LTIP) Award Agreement under the Amended and Restated 2011 Ashland Inc. Incentive Plan (filed as Exhibit 10.17 to Ashland's Form 10-K for the fiscal year ended September 30, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.26 – Form of Restricted Stock Award Agreement under the Amended and Restated 2011 Ashland Inc. Incentive Plan (filed as Exhibit 10.18 to Ashland's Form 10-K for the fiscal year ended September 30, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.27 – Form of Restricted Stock Unit Agreement under the Amended and Restated 2011 Ashland Inc. Incentive Plan (filed as Exhibit 10.19 to Ashland's Form 10-K for the fiscal year ended September 30, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.28 – Form of Restricted Stock Award Agreement under the Amended and Restated 2015 Ashland Inc. Incentive Plan (filed as Exhibit 10.5 to Ashland's Form 10-Q for the quarter ended March 31, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.29 – Form of Restricted Stock Unit Award Agreement under the Amended and Restated 2015 Ashland Inc. Incentive Plan (filed as Exhibit 10.6 to Ashland's Form 10-Q for the quarter ended March 31, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.30 – Form of Stock Appreciation Rights Award Agreement under the Amended and Restated 2015 Ashland Inc. Incentive Plan (filed as Exhibit 10.7 to Ashland's Form 10-Q for the quarter ended March 31, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.31 – Form of Performance Unit (LTIP) Award Agreement under the Amended and Restated 2015 Ashland Inc. Incentive Plan (filed as Exhibit 10.8 to Ashland's Form 10-Q for the quarter ended March 31, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.32 – Form of Restricted Stock Award Agreement under the Amended and Restated 2015 Ashland Inc. Incentive Plan (Double-Trigger Form) (filed as Exhibit 10.2 to Ashland's Form 8-K filed on July 20, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.33 – Form of Restricted Stock Unit Award Agreement under the Amended and Restated 2015 Ashland Inc. Incentive Plan (Double-Trigger Form) (filed as Exhibit 10.3 to Ashland's Form 8-K filed on July 20, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.34 – Form of Stock Appreciation Rights Award Agreement under the Amended and Restated 2015 Ashland Inc. Incentive Plan (Double-Trigger Form) (filed as Exhibit 10.4 to Ashland's Form 8-K filed on July 20, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.35 – Form of Performance Unit (LTIP) Award Agreement under the Amended and Restated 2015 Ashland Inc. Incentive Plan (Double-Trigger Form) (filed as Exhibit 10.5 to Ashland's Form 8-K filed on July 20, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.36 – Letter Agreement between Ashland and Luis Fernandez-Moreno dated July 29, 2013 (filed as Exhibit 10.22 to Ashland's Form 10-K for the fiscal year ended September 30, 2013 (SEC File No. 001- 32532), and incorporated herein by reference).

10.37 – Letter Agreement between Ashland and Luis Fernandez-Moreno dated November 4, 2013 (filed as Exhibit 10.23 to Ashland's Form 10-K for the fiscal year ended September 30, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

10.38 – Letter Agreement between Ashland and Susan B. Esler dated October 28, 2014 (filed as Exhibit 10.25 to Ashland's Form 10-K for the fiscal year ended September 30, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.39 – Letter Agreement between Ashland and William A. Wulfsohn, dated November 12, 2014 (filed as Exhibit 10.1 to Ashland's Form 8-K filed on November 17, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.40** – Separation Agreement and General Release between Ashland and Susan B. Esler dated October 1, 2015.

10.41** – Separation Agreement and General Release between Ashland and Walter H. Solomon dated October 1, 2015.

10.42 – Form of Performance-Based Restricted Stock Award Agreement (filed as Exhibit 10.3 to Ashland's Form 8-K filed on October 9, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.43** – Form of Retention Award Agreement for certain Executive Officers.

10.44 – Stock Purchase Agreement dated as of May 30, 2011, entered into by and among The Samuel J. Heyman 1981 Continuing Trust for Lazarus S. Heyman, The Samuel J. Heyman 1981 Continuing Trust for Eleanor S. Heyman, The Samuel J. Heyman 1981 Continuing Trust for Jennifer L. Heyman, The Samuel J. Heyman 1981 Continuing Trust for Elizabeth D. Heyman, The Lazarus S. Heyman Age 50 Trust for Assets Appointed Under Will of Lazarus S. Heyman, The Eleanor S. Heyman Age 50 Trust for Assets Appointed Under Will of Lazarus S. Heyman, The Jennifer L. Heyman Age 50 Trust for Assets Appointed Under Will of Lazarus S. Heyman, The Elizabeth D. Heyman Age 50 Trust for Assets Appointed Under Will of Lazarus S. Heyman, The Horizon Holdings Residual Trust, RFH Investment Holdings LLC, Ashland and Ronnie F. Heyman, as representative of the Seller Parties (filed as Exhibit 2.1 to Ashland's Form 8-K filed on May 31, 2011 (SEC File No. 001-32532), and incorporated herein by reference).

10.45 – Master Formation Agreement dated July 15, 2010, among Ashland, Süd-Chemie Aktiengesellschaft and Ashland-Südchemie-Kernfest GmbH (filed as Exhibit 10.26 to Ashland's Form 10-K for the fiscal year ended September 30, 2010 (SEC File No. 001-32532), and incorporated herein by reference).

10.46 – Master Contribution and Sale Agreement dated July 15, 2010, among Ashland, Ashland International Holdings, Inc., Süd-Chemie Aktiengesellschaft, Tecpro Holding Corporation Inc. and Ashland-Südchemie-Kernfest GmbH (filed as Exhibit 10.27 to Ashland's Form 10-K for the fiscal year ended September 30, 2010 (SEC File No. 001-32532), and incorporated herein by reference).

10.47 – Shareholders' Agreement effective November 30, 2010 by and between Süd-Chemie Aktiengesellschaft and Süd-Chemie Finance GmbH and Ashland and Ashland International Holdings, Inc. (filed as Exhibit 10 to Ashland's Form 10-Q for the quarter ended December 31, 2010 (SEC File No. 001-32532), and incorporated herein by reference).

10.48 – Credit Agreement dated as of March 14, 2013, among Ashland Inc., as Borrower, The Bank of Nova Scotia, as Administrative Agent, Swing Line Lender and an L/C Issuer, Citibank, N.A., as Syndication Agent, Bank of America, N.A., Deutsche Bank Securities Inc. and PNC Bank, National Association, as Co-Documentation Agents, and the Lenders from time to time party thereto (filed as Exhibit 10.1 to Ashland's Form 8-K filed on March 15, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

10.49 – Amendment Agreement, dated as of February 5, 2014, to the Credit Agreement dated as of March 14, 2013, among Ashland Inc., as Borrower, The Bank of Nova Scotia, as Administrative Agent, and each Lender from time to time party thereto and the other agents and arrangers party thereto (filed as Exhibit 10.2 to Ashland's Form 10-Q for the quarter ended March 31, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.50 – Amendment No. 2, dated as of February 27, 2015, to the Credit Agreement, dated as of March 14, 2013, as amended by the Amendment Agreement, dated as of February 5, 2014, among Ashland Inc., as Borrower, The Bank of Nova Scotia, as Administrative Agent, each Lender from time to time party thereto and the other agents and arrangers party thereto (filed as Exhibit 10.3 to Ashland's Form 10-Q for the quarter ended March 31, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.51 – Credit Agreement dated as of June 23, 2015, among Ashland Inc., as Borrower, The Bank of Nova Scotia, as Administrative Agent, Swing Line Lender and an L/C Issuer, Citibank, N.A., as Syndication Agent, Bank of America, N.A., Deutsche Bank Securities Inc. and PNC Bank, National Association, as Co-Documentation Agents, JPMorgan Chase Bank, N.A., Mizuho Bank LTD., U.S. Bank National Association, and Wells Fargo Bank, National Association, as Managing Agents, and the other Lenders party thereto (filed as Exhibit 10.1 to Ashland's Form 8-K filed on June 23, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.52 – Transfer and Administration Agreement, dated as of August 31, 2012, among CVG Capital III LLC, Ashland Inc., Hercules Incorporated, Aqualon Company, ISP Technologies Inc., ISP Synthetic Elastomers LLC, and each other entity from time to time party thereto as an Originator, as Originators, Ashland Inc., as initial Master Servicer, each of Liberty Street Funding LLC, Market Street Funding LLC and Gotham Funding Corporation, as Conduit Investors and Uncommitted Investors, The Bank of Nova Scotia, as the Agent, a Letter of Credit Issuer, a Managing Agent, an Administrator and a Committed Investor, and the Letter of Credit Issuers, Managing Agents, Administrators, Uncommitted Investors and Committed Investors parties thereto from time to time (filed as Exhibit 10.1 to Ashland's Form 8-K filed on September 7, 2012 (SEC File No. 001-32532), and incorporated herein by reference).

10.53 – Sale Agreement, dated as of August 31, 2012, among Ashland Inc., Hercules Incorporated, Aqualon Company, ISP Technologies Inc., ISP Synthetic Elastomers LLC and CVG Capital III LLC (filed as Exhibit 10.2 to Ashland's Form 8-K filed on September 7, 2012 (SEC File No. 001-32532), and incorporated herein by reference).

10.54 – Parent Undertaking, dated as of August 31, 2012, by Ashland Inc. in favor of The Bank of Nova Scotia and the Secured Parties (filed as Exhibit 10.3 to Ashland's Form 8-K filed on September 7, 2012 (SEC File No. 001-32532), and incorporated herein by reference).

10.55 – First Amendment to Transfer and Administration Agreement, dated as of April 30, 2013, among Ashland Inc., CVG Capital III LLC, the Investors, Letter of Credit Issuers, Managing Agents and Administrators party thereto, and the Bank of Nova Scotia, as Agent for the Investors (filed as Exhibit 10.2 to Ashland's Form 10-Q for the quarter ended June 30, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

10.56 – Omnibus Amendment to Transfer and Administration Agreement, dated as of August 21, 2013, among Ashland Inc., CVG Capital III LLC, the Originators, the Investors, Letter of Credit Issuers, Managing Agents and Administrators party thereto, and the Bank of Nova Scotia, as Agent for the Investors (filed as Exhibit 10.34 to Ashland's Form 10-K for the fiscal year ended September 30, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

10.57 – Third Amendment to Transfer and Administration Agreement, dated as of October 15, 2013, among Ashland Inc., CVG Capital III LLC, the Originators, the Investors, Letter of Credit Issuers, Managing Agents and Administrators party thereto, and the Bank of Nova Scotia, as Agent for the Investors (filed as Exhibit 10.35 to Ashland's Form 10-K for the fiscal year ended September 30, 2013 (SEC File No. 001-32532), and incorporated herein by reference).

10.58 – Fourth Amendment to Transfer and Administration Agreement, dated as of June 30, 2014, among Ashland Inc., CVG Capital III LLC, the Originators, the Investors, Letter of Credit Issuers, Managing Agents and Administrators party thereto, and the Bank of Nova Scotia, as Agent for the Investors (filed as Exhibit 10.1 to Ashland's Form 10-Q for the quarter ended June 30, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.59 – Receivables Assignment Agreement, dated as of November 25, 2014, among Ashland Inc., as originator and master servicer, CVG Capital III LLC, Ashland Specialty Ingredients G.P., the Investors, Letter of Credit Issuers, Managing Agent and Administrators party thereto, and the Bank of Nova Scotia, as Agent for the Investors (filed as Exhibit 10.4 to Ashland's Form 10-Q for the quarter ended December 31, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.60 – Sixth Amendment to Transfer and Administration Agreement, dated as of November 25, 2014, among Ashland Inc., CVG Capital III LLC, the Originators, the Investors, Letter of Credit Issuers, Managing Agents and Administrators party thereto, and the Bank of Nova Scotia, as Agent for the Investors (filed as Exhibit 10.5 to Ashland's Form 10-Q for the quarter ended December 31, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.61 – Seventh Amendment dated as of August 28, 2015 to the Transfer and Administration Agreement dated as of August 31, 2012, among Ashland Inc., CVG Capital III LLC, the Originators, the Investors, Letter of Credit Issuers, Managing Agents and Administrators party thereto, and The Bank of Nova Scotia, as agent for the Investors (filed as Exhibit 10.1 to Ashland's Form 8-K filed on September 2, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.62 – Eighth Amendment dated as of September 30, 2015 to the Transfer and Administration Agreement as of August 31, 2012, among Ashland Inc., CVG Capital III LLC, the Originators, the Investors, Letter of Credit Issuers, Managing Agents and Administrators party thereto, and The Bank of Nova Scotia, as agent for the Investors (filed as Exhibit 10.1 to Ashland's Form 8-K filed on October 6, 2015 (SEC File No. 001-32532), and incorporated herein by reference).

10.63 – First Amendment to Sale Agreement, dated as of June 30, 2014, among Ashland Inc., Hercules Incorporated, Ashland Specialty Ingredients G.P., ISP Technologies Inc., Ashland Elastomers LLC and CVG Capital III LLC (filed as Exhibit 10.2 to Ashland's Form 10-Q for the quarter ended June 30, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.64 – Originator Removal Agreement and Facility Amendment, dated as of July 28, 2014, by and among Ashland, Hercules Incorporated, Ashland Specialty Ingredients G.P., ISP Technologies Inc., Ashland Elastomers LLC, CVG Capital III LLC, the Investors, the Letter of Credit Issuers, Managing Agents and Administrators party thereto, and the Bank of Nova Scotia, as Agent for the Investors (filed as Exhibit 10.1 to Ashland's Form 8-K filed on August 1, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.65 – Master Confirmation - Uncollared Accelerated Share Repurchase, dated August 5, 2014, between Ashland Inc. and Deutsche Bank AG, London Branch (filed as Exhibit 10.1 to Ashland's Form 8-K filed on August 6, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

10.66 – Master Confirmation – Uncollared Accelerated Share Repurchase, dated August 5, 2014, between Ashland Inc. and J.P. Morgan Securities LLC, as agent for JPMorgan Chase Bank, N.A. (filed as Exhibit 10.2 to Ashland's Form 8-K filed on August 6, 2014 (SEC File No. 001-32532), and incorporated herein by reference).

11** – Computation of Earnings Per Share (appearing in Note A of Notes to Consolidated Financial Statements in this annual report on Form 10-K).

12** – Computation of Ratio of Earnings to Fixed Charges.

21** – List of Subsidiaries.

23.1** – Consent of Ernst & Young LLP.

23.2** – Consent of PricewaterhouseCoopers LLP.

23.3** – Consent of Hamilton, Rabinovitz & Associates, Inc.

24** – Power of Attorney.

31.1** – Certification of William A. Wulfsohn, Chief Executive Officer of Ashland, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2** – Certification of J. Kevin Willis, Chief Financial Officer of Ashland, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32**	–	Certification of William A. Wulfsohn, Chief Executive Officer of Ashland, and J. Kevin Willis, Chief Financial Officer of Ashland, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*		XBRL Instance Document.
101.SCH*		XBRL Taxonomy Extension Schema Document.
101.CAL*		XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*		XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*		XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*		XBRL Taxonomy Extension Presentation Linkbase Document.

*Attached as Exhibit 101 to this report are the following documents formatted in XBRL (Extensible Business Reporting Language): (i) Statements of Consolidated Comprehensive Income for years ended September 30, 2015, 2014 and 2013; (ii) Consolidated Balance Sheets at September 30, 2015 and 2014; (iii) Statements of Consolidated Stockholders' Equity at September 30, 2015, 2014 and 2013; (iv) Statements of Consolidated Cash Flows for years ended September 30, 2015, 2014 and 2013; and (v) Notes to Consolidated Financial Statements.

**Filed herewith.

℠ Service mark, Ashland or its subsidiaries, registered in various countries.

™ Trademark, Ashland or its subsidiaries, registered in various countries.

† Trademark owned by a third party.

Upon written or oral request, a copy of the above exhibits will be furnished at cost.

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.

ASHLAND INC.
(Registrant)
By:
/s/ J. Kevin Willis
J. Kevin Willis
Senior Vice President and Chief Financial Officer
Date: November 20, 2015

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, in the capacities indicated, on November 20, 2015.

Signatures	**Capacity**
/s/ William A. Wulfsohn William A. Wulfsohn	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)
/s/ J. Kevin Willis J. Kevin Willis	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ J. William Heitman J. William Heitman	Vice President and Controller (Principal Accounting Officer)
* Brendan M. Cummins	Director
* Roger W. Hale	Director
* Stephen F. Kirk	Director
* Vada O. Manager	Director
* Barry W. Perry	Director
* Mark C. Rohr	Director
* George A. Schaefer, Jr.	Director
* Janice J. Teal	Director
* Michael J. Ward	Director

*By: /s/ Peter J. Ganz
Peter J. Ganz
Attorney-in-Fact

Date: November 20, 2015

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

The following discussion should be read in conjunction with the Consolidated Financial Statements and the accompanying Notes to Consolidated Financial Statements for the years ended September 30, 2015, 2014 and 2013.

BUSINESS OVERVIEW

Ashland profile

Ashland is a global leader in specialty chemicals and, through Valvoline, a premium consumer-branded lubricant supplier. Ashland provides products, services and solutions that meet customers' needs throughout a variety of industries in more than 100 countries. Its chemistry is used in a wide variety of markets and applications, including architectural coatings, adhesives, automotive, construction, energy, food and beverage, personal care, and pharmaceutical. With approximately 10,500 employees worldwide, Ashland serves customers in more than 100 countries.

Ashland's sales generated outside of North America were 47% in 2015 and 2014, and 46% in 2013. Sales by region expressed as a percentage of total consolidated sales were as follows:

Sales by Geography	2015	2014	2013
North America (a)	53%	53%	54%
Europe	24%	25%	24%
Asia Pacific	16%	15%	15%
Latin America & other	7%	7%	7%
	100%	100%	100%

(a) Ashland includes only U.S. and Canada in its North American designation.

Reportable segments

Ashland's reporting structure is composed of three reportable segments: Ashland Specialty Ingredients (Specialty Ingredients), Ashland Performance Materials (Performance Materials) and Valvoline. For further descriptions of each reportable segment, see "Results of Operations – Reportable Segment Review" beginning on page M-13.

Sales by each reportable segment expressed as a percentage of total consolidated sales were as follows:

Sales by Reportable Segment	2015	2014	2013
Specialty Ingredients	42%	41%	41%
Performance Materials	21%	26%	26%
Valvoline	37%	33%	33%
	100%	100%	100%

KEY DEVELOPMENTS

During 2015, the following operational decisions and economic developments had an impact on Ashland's current and future cash flows, results of operations and financial position.

Business results

Ashland's overall financial performance increased by 4% during 2015 compared to 2014 as adjusted EBITDA results increased to $1,119 million (see U.S. GAAP reconciliation on page M-7). The increase in adjusted EBITDA was primarily attributable to improved results within the Valvoline reportable segment, partially offset by a decline in the Performance Materials and Specialty Ingredients reportable segments. Compared to 2014, Valvoline's adjusted EBITDA results increased $51 million, or 14%, primarily due to lower raw material costs, specifically relating to the price of base oil, which resulted in increased gross profit. Additionally, lower selling, general and administrative expense, primarily due to cost savings from the 2014 global restructuring, contributed to Valvoline's improved results. Performance Materials' adjusted EBITDA results decreased by $20 million, or 12%, as lower production costs, which contributed to improved gross profit, and selling, general and administrative expense compared to the prior year were more than offset by the lost income from the divestiture of the Elastomers division and significant plant maintenance

shutdowns at both Intermediates/Solvents manufacturing facilities. Specialty Ingredients' adjusted EBITDA results remained relatively consistent, decreasing only $2 million compared to the prior year, primarily as a result of improved gross profit from lower raw material costs and cost savings from the 2014 global restructuring. These favorable results were more than offset by weak energy market results and unfavorable foreign currency exchange.

The following discussion outlines significant transactions announced or executed during 2015.

Ashland Separation of Valvoline

On September 22, 2015, Ashland announced that the Board of Directors approved proceeding with a plan to separate Ashland into two independent, publicly traded companies comprising of the new Ashland and Valvoline. Ashland has begun the process to separate its Valvoline business from its Specialty Ingredients and Performance Materials businesses while it finalizes the transaction structure and obtains customary regulatory and other approvals. Ashland intends for the separation, which is subject to final board approval prior to completion, to be tax free for Ashland shareholders. Immediately following the separation, Ashland shareholders will own shares of both the new Ashland and Valvoline. The separation is expected to be completed as soon as practicable, but not before the end of fiscal 2016.

The new Ashland will be a global leader in providing specialty chemical solutions to customers in a wide range of consumer and industrial markets. These markets are currently served by Specialty Ingredients and Performance Materials. Key markets and applications include pharmaceutical, personal care, food and beverage, architectural coatings, adhesives, automotive, construction and energy. Together these businesses generated approximately $3.4 billion in sales for the fiscal year ended September 30, 2015.

Valvoline will focus on building the world's leading engine and automotive maintenance business by providing hands-on expertise to customers in each of its primary market channels: Do-It-Yourself (DIY); Installers; Valvoline Instant Oil Change℠; and International. Valvoline generated sales of $2 billion for Ashland during the fiscal year ended September 30, 2015.

Acquisition

Zeta Fraction™

In September 2015, Specialty Ingredients completed the acquisition of the patented Zeta Fraction™ technology from AkzoNobel. The acquisition broadens Ashland's value-added portfolio in the personal care, pharmaceutical, food and beverage, and agriculture markets. The patented Zeta Fraction™ process and technology selectively isolates efficacious components from living plants and marine sources to produce a wide range of biofunctional ingredients.

Divestitures

Industrial Biocides

During May 2015, Ashland entered into a definitive sale agreement to sell the industrial biocides assets within Specialty Ingredients, which closed on July 1, 2015. As a result of the sale, Ashland received net cash proceeds of approximately $30 million during the fourth quarter of 2015 and recognized a nominal gain before tax and after customary closing costs within the net gain (loss) on divestitures caption within the Statements of Consolidated Comprehensive Income.

The sale of Specialty Ingredients' industrial biocides assets did not qualify for discontinued operations treatment since it did not represent a strategic shift that had or will have a major effect on Ashland's operations and financial results.

Valvoline Car Care Products

In April 2015, Ashland entered into a definitive sale agreement to sell Valvoline's car care product assets for $24 million, which included Car Brite™ and Eagle One™ automotive appearance products. Prior to the sale, Ashland recognized a loss of $26 million before tax in 2015 to recognize the assets at fair value less cost to sell. The loss is reported within the net gain (loss) on divestitures caption within the Statements of Consolidated Comprehensive Income. The transaction closed on June 30, 2015 and Ashland received net proceeds of $19 million after adjusting for certain customary closing costs and final working capital totals.

The sale of Valvoline's car care product assets did not qualify for discontinued operations treatment since it did not represent a strategic shift that had or will have a major effect on Ashland's operations and financial results.

Valvoline Joint Venture

During April 2015, Ashland sold a Valvoline joint venture equity investment in Venezuela. Prior to the sale, Ashland recognized a $14 million impairment in 2015, for which there was no tax effect, within the equity and other income caption of the Statements of Consolidated Comprehensive Income.

Ashland's decision to sell the equity investment and the resulting charge recorded during 2015 is reflective of the continued devaluation of the Venezuelan currency (bolivar) based on changes to the Venezuelan currency exchange rate mechanisms during the fiscal year. In addition, the continued lack of exchangeability between the Venezuelan bolivar and U.S. dollar had restricted

the joint venture's ability to pay dividends and obligations denominated in U.S. dollars. These exchange regulations and cash flow limitations, combined with other recent Venezuelan regulations and the impact of declining oil prices on the Venezuelan economy, had significantly restricted Ashland's ability to conduct normal business operations through the joint venture arrangement. Ashland determined this divestiture does not represent a strategic shift that had or will have a major effect on Ashland's operations and financial results, and thus it does not qualify for discontinued operations treatment.

Elastomers

On October 9, 2014, Ashland entered into a definitive agreement to sell the Elastomers division within the Performance Materials reportable segment, which operated a 250-person manufacturing facility in Port Neches, Texas, to Lion Copolymer Holdings, LLC. The Elastomers division, which primarily served the North American replacement tire market, accounted for approximately 5% of Ashland's 2014 sales of $6.1 billion and 18% of Ashland Performance Materials' $1.6 billion in sales in 2014. The sale was completed on December 1, 2014 in a transaction valued at approximately $120 million which was subject to working capital adjustments. The total post-closing adjusted cash proceeds received before taxes by Ashland during 2015 was $105 million, which includes working capital adjustments and transaction costs, as defined in the definitive agreement.

Elastomers' net assets as of November 30, 2014 were $191 million which primarily included accounts receivable, inventory, property, plant and equipment, non-deductible goodwill and other intangibles and payables. Since the net proceeds received were less than book value, Ashland recorded a loss of $86 million pre-tax, within the net gain (loss) on divestiture caption of the Statements of Consolidated Comprehensive Income during 2015. The related tax effect was a benefit of $28 million included in the income tax expense (benefit) caption within the Statements of Consolidated Comprehensive Income.

Ashland determined that the sale of Elastomers did not represent a strategic shift that had or will have a major effect on Ashland's operations and financial results. As such, Elastomers' results were included in the Performance Materials reportable segment results of operations and financial position within the Statements of Consolidated Comprehensive Income and Consolidated Balance Sheets, respectively, until its December 1, 2014 sale. Certain indirect corporate costs of $11 million for 2015 were included within the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income that were previously allocated to the Elastomers division and are now reported as selling, general and administrative expense within continuing operations on a consolidated basis within the Unallocated and other segment.

Financial position

During 2015, Ashland has continued its focus on executing its capital allocation strategies. The following highlights key transactions during 2015.

Stock repurchase programs

During 2015, Ashland's Board of Directors approved a new $1 billion share repurchase authorization that will expire on December 31, 2017. This authorization allows for the same repurchase methods as the 2014 repurchase program. During the first quarter of 2016, under this new share repurchase authorization, Ashland announced that it entered into an accelerated share repurchase agreement (November 2015 ASR Agreement) with Goldman, Sachs & Co. Under the November 2015 ASR Agreement, Ashland paid an initial purchase price of $500 million and received an initial delivery of approximately 3.9 million shares of common stock during November 2015. The November 2015 ASR Agreement is scheduled to terminate no later than May 2016 but may be terminated early in certain circumstances, in whole or in part.

During 2014, the Board of Directors of Ashland authorized a $1.35 billion common stock repurchase program. Under this program, Ashland's common shares could be repurchased in open market transactions, privately negotiated transactions or pursuant to one or more accelerated stock repurchase programs or Rule 10b5-1 plans. Ashland completed this program during 2015. The following summarizes stock repurchase agreements that were entered into as part of the $1.35 billion common stock repurchase program.

- In 2014, completed a prepaid variable share repurchase agreement for $80 million and received 0.8 million shares.
- In 2014, entered into $750 million of accelerated share repurchase agreements that were completed during 2015 and received 6.4 million shares, of which 0.5 million shares were received during 2015.
- In 2014, entered into $250 million of share repurchase agreements that were completed during 2015 and received 2.4 million shares, of which 1.2 million were repurchased during 2015.
- In 2015, entered into $270 million of accelerated share repurchase agreements that were completed during 2015 and received 2.2 million shares.

In total, Ashland spent $1.35 billion in stock repurchase programs and received approximately 11.8 million shares of common stock.

Senior notes refinancing and 2015 Senior Credit Agreement

During June of 2015, Ashland completed certain refinancing transactions related to the $600 million 3.000% senior notes due in 2016 (2016 senior notes). Ashland commenced and completed a cash tender offer to purchase for cash any and all of its outstanding 2016 senior notes. At the close of the tender offer, $550 million aggregate principal amount of the 2016 senior notes was tendered by note holders, representing approximately 92% of the outstanding 2016 senior notes, which have been purchased by Ashland. Subsequently, Ashland redeemed the remaining balance of the 2016 senior notes of $50 million on July 23, 2015.

In connection with the tender offer and redemption, in June 2015, Ashland entered into a new Credit Agreement (the 2015 Senior Credit Agreement). The 2015 Senior Credit Agreement replaced the $1.2 billion senior unsecured revolving credit facility (the 2013 Senior Credit Facility), and was comprised of a new five-year senior unsecured revolving credit facility in an aggregate amount of $1.2 billion (the 2015 revolving credit facility), which includes a $250 million letter of credit sublimit and a $100 million swing line loan sublimit, and a five-year senior unsecured term loan facility in an aggregate principal amount of $1.1 billion (the term loan facility). The 2015 Senior Credit Agreement is not guaranteed, is unsecured and can be prepaid at any time without premium or penalty.

During 2015, Ashland used the proceeds from borrowings under the $1.1 billion term loan facility along with cash on hand (i) to fund the tender offer of the 2016 senior notes, (ii) to pay in full the outstanding loans under the 2013 Senior Credit Facility, (iii) to pay accrued interest, fees and expenses under the 2013 Senior Credit Facility and the 2016 senior notes, (iv) to contribute funds to the U.S. pension plans impacted by the pension plan settlement program discussed in Note M in Notes to Consolidated Financial Statements, and (v) to pay fees and expenses incurred in connection with the entry into the 2015 Senior Credit Agreement. As a result of the tender offer and redemption, Ashland recognized a $9 million charge related to early redemption premium payments, which is included in the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income in 2015.

Pension plan settlement program

During 2015, Ashland informed approximately 20,000 former employees, who were included in the approximately 53,000 participants within the primary U.S. pension plans, that Ashland was offering these participants the option of receiving a lump sum payment on their vested retirement benefit or a reduced annuity now, in lieu of receiving monthly annuity payments deferred until retirement eligibility or when the participant may choose to initiate payment. During August 2015, approximately 12,000 participants elected to participate in the settlement program which resulted in approximately $475 million in settlement payments made from the affected pension plans during September 2015. Settlement payments were funded with pension plan assets, which included the $500 million contribution made during the third quarter of fiscal 2015.

Accounts receivable securitization

During 2015, the termination of the commitments under the Transfer and Administration Agreement under the accounts receivable securitization was extended from August 28, 2015 to December 31, 2015. See Note I of the Notes to Consolidated Financial Statements for further information on this agreement.

Credit ratings

During 2015, Ashland's corporate credit ratings remained unchanged at BB by Standard & Poor's and Ba1 by Moody's Investor Services. As of September 30, 2015, Moody's Investor Services affirmed Ashland's outlook as stable, while Standard & Poor revised Ashland's outlook to negative following Ashland's announcement of its intent to separate the Valvoline business via a tax-free separation to its shareholders and not as a result of Ashland's ongoing operations. Ashland's ability to access capital markets to provide liquidity has remained largely unchanged as a result of the ratings; however, improvements in the credit markets and Ashland's financial performance has allowed, and should continue in the future to allow, Ashland to borrow on more favorable terms, including less restrictive covenants and lower interest rates.

Insurance settlement

On January 13, 2015, Ashland and Hercules entered into a comprehensive settlement agreement related to certain insurance coverage for asbestos bodily injury claims with Underwriters at Lloyd's, certain London companies and Chartis (AIG) member companies, along with National Indemnity Company and Resolute Management, Inc., under which Ashland and Hercules received a total of $398 million. In exchange, all claims were released against these entities for past, present and future coverage obligations arising out of the asbestos coverage-in-place agreements that were the subject of the pending arbitration proceedings. In addition, as part of this settlement, Ashland and Hercules released all claims against National Indemnity Company and Resolute Management, Inc. in the Kentucky state court action. As a result, the arbitration proceedings and the Kentucky state court action have been terminated.

As a result of this settlement, during 2015, Ashland recorded an after-tax gain of $120 million within the discontinued operations caption of the Statements of Consolidated Comprehensive Income and a $249 million reduction in the asbestos insurance receivable

balance, consisting of $227 million and $22 million for Ashland and Hercules, respectively, within the Consolidated Balance Sheets. See Note N of the Notes to Consolidated Financial Statements for further information.

In addition, Ashland placed $335 million of the settlement funds received into a renewable annual trust restricted for the purpose of paying for ongoing and future litigation defense and claim settlement costs incurred in conjunction with asbestos claims. These funds are presented primarily as noncurrent assets, with $30 million classified within other current assets in the Consolidated Balance Sheets.

Global restructuring

During 2014, in conjunction with the divestitures of Water Technologies and the Casting Solutions joint venture, Ashland initiated a global restructuring program to streamline the resources used across the organization. The global restructuring program improved operational performance while recognizing significant annualized cost savings. As of September 30, 2015, Ashland's global restructuring program, which targeted $200 million in annualized run-rate cost savings, is complete. The cost savings associated with the restructuring program have been recognized within cost of sales and selling, general, and administrative expenses during 2014 and 2015. See Note E of the Notes to Consolidated Financial Statements for further information.

RESULTS OF OPERATIONS – CONSOLIDATED REVIEW

Use of non-GAAP measures

Ashland has included within this document certain non-GAAP measures which include EBITDA (net income, plus income tax expense (benefit), net interest and other financing expenses, and depreciation and amortization), Adjusted EBITDA (EBITDA adjusted for discontinued operations, net gain (loss) on acquisitions and divestitures, other income and (expense) and key items, which may include pro forma effects for significant acquisitions or divestitures, as applicable) and Adjusted EBITDA margin (Adjusted EBITDA, which can include pro forma adjustments, divided by sales). Such measurements are not prepared in accordance with U.S. GAAP and as related to pro forma adjustments, contain Ashland's best estimates of cost allocations and shared resource costs. Management believes the use of non-GAAP measures on a consolidated and reportable segment basis assists investors in understanding the ongoing operating performance by presenting comparable financial results between periods. The non-GAAP information provided is used by Ashland management and may not be determined in a manner consistent with the methodologies used by other companies. EBITDA and Adjusted EBITDA provide a supplemental presentation of Ashland's operating performance on a consolidated and reportable segment basis. Adjusted EBITDA generally includes adjustments for unusual, non-operational or restructuring-related activities. In addition, certain financial covenants related to Ashland's 2015 Senior Credit Agreement are based on similar non-GAAP measures and are defined further in the sections that reference this metric.

In accordance with U.S. GAAP, Ashland recognizes actuarial gains and losses for defined benefit pension and other postretirement benefit plans annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement during a fiscal year. Actuarial gains and losses occur when actual experience differs from the estimates used to allocate the change in value of pension and other postretirement benefit plans to expense throughout the year or when assumptions change, as they may each year. Significant factors that can contribute to the recognition of actuarial gains and losses include changes in discount rates used to remeasure pension and other postretirement obligations on an annual basis or upon a qualifying remeasurement, differences between actual and expected returns on plan assets and other changes in actuarial assumptions, for example the life expectancy of plan participants. Management believes Adjusted EBITDA, which includes the expected return on pension plan assets and excludes both the actual return on pension plan assets and the impact of actuarial gains and losses, provides investors with a meaningful supplemental presentation of Ashland's operating performance. Management believes these actuarial gains and losses are primarily financing activities that are more reflective of changes in current conditions in global financial markets (and in particular interest rates) that are not directly related to the underlying business and that do not have an immediate, corresponding impact on the compensation and benefits provided to eligible employees and retirees. For further information on the actuarial assumptions and plan assets referenced above, see MD&A - Critical Accounting Policies - Employee benefit obligations and Note M of the Notes to Consolidated Financial Statements.

Ashland has included free cash flow as an additional non-GAAP metric of cash flow generation. Ashland believes free cash flow is relevant because capital expenditures are an important element of Ashland's ongoing cash activities. By deducting capital expenditures and certain other adjustments as applicable from operating cash flows, Ashland is able to provide a better indication of the ongoing cash being generated that is ultimately available for both debt and equity holders as well as other investment opportunities. Prior to 2013, Ashland deducted dividends from this calculation but has discontinued this practice to be more comparable to the broader market's calculation of free cash flow.

Consolidated review

Net income

Ashland's net income is primarily affected by results within operating income, net interest and other financing expense, income taxes, discontinued operations and other significant events or transactions that are unusual or nonrecurring. Operating income includes Ashland's adjustment for the immediate recognition of the change in the fair value of the plan assets and net actuarial gains and losses for defined benefit pension plans and other postretirement benefit plans each fiscal year. See "Critical Accounting Policies" for additional details regarding Ashland's accounting policies for benefit plan obligations.

Key financial results for 2015, 2014 and 2013 included the following:

- Ashland's net income amounted to $309 million in 2015, $233 million in 2014 and $683 million in 2013, or $4.48, $3.00 and $8.57 diluted earnings per share, respectively.
- Discontinued operations, which are reported net of taxes, resulted in income of $118 million, $161 million and $130 million during 2015, 2014 and 2013, respectively.
- Income from continuing operations, which excludes results from discontinued operations, amounted to $191 million in 2015, $72 million in 2014 and $553 million in 2013, or $2.78, $0.93 and $6.95 diluted earnings per share, respectively.
- The effective income tax benefit rate of 13% for 2015, income tax benefit rate of 162% for 2014, and the income tax expense rate of 26% for 2013, were significantly affected by a number of discrete items.
- Ashland incurred pretax net interest and other financing expense of $174 million, $166 million and $282 million during 2015, 2014 and 2013, respectively. Certain charges associated with debt refinancing activity impacted 2015 and 2013.
- Operating income was $458 million, $46 million and $1,039 million during 2015, 2014 and 2013, respectively.

For further information on the items reported above, see the discussion in the comparative Statements of Consolidated Comprehensive Income caption review analysis.

Operating income

Operating income amounted to $458 million, $46 million and $1,039 million in 2015, 2014 and 2013, respectively. The current and prior years' operating income include certain key items that are excluded to arrive at Adjusted EBITDA. These key items are summarized as follows:

- Expense of $255 million and $438 million in 2015 and 2014, respectively, and income of $417 million in 2013 from the immediate recognition from the change in the fair value of the plan assets and net actuarial gains and losses for defined benefit pension plans and other postretirement benefit plans;
- Restructuring and integration costs include the following:
    - $27 million of restructuring costs (including $6 million of accelerated depreciation and $17 million related to the restructuring plan within an existing manufacturing facility) during 2015;
    - $147 million of restructuring and integration costs (including $17 million of accelerated depreciation and $19 million in asset impairment charges related to a foreign operation) during 2014; and
    - $29 million of restructuring and other integration costs during 2013;
- a $14 million impairment related to the Valvoline joint venture equity investment within Venezuela during 2015 and a $50 million impairment charge related to the ASK joint venture equity investment during 2014;
- $12 million, $13 million and $16 million net environmental charges during 2015, 2014 and 2013, respectively;
- $11 million, $13 million and $41 million impairment charges related to certain in-process research and development (IPR&D) assets associated with the acquisition of International Specialty Products Inc. (ISP) in 2011 during 2015, 2014 and 2013, respectively;
- $16 million of tax indemnity income, a $13 million charge related to a customer claim, and a $7 million charge for a stock incentive plan award modification, each during 2015;
- two $5 million charges for a foreign tax indemnification receivable adjustment and a legal reserve, respectively, during 2014; and

- $22 million and $13 million gains resulting from Ashland's settlement of an insurance claim and settlement of a customer claim, respectively, during 2013.

Operating income for 2015, 2014 and 2013 included depreciation and amortization of $335 million, $357 million and $354 million, respectively (which excludes asset impairment charges and accelerated depreciation of $6 million, $36 million and $2 million, respectively, for each year). EBITDA totaled $796 million, $568 million and $1,515 million for 2015, 2014 and 2013, respectively. Adjusted EBITDA results in the following table have been prepared to illustrate the ongoing effects of Ashland's operations, which exclude certain key items since management believes the use of such non-GAAP measures on a consolidated and reportable segment basis assists investors in understanding the ongoing operating performance by presenting the financial results between periods on a more comparable basis.

(In millions)	2015	2014	2013
Net income	$ 309	$ 233	$ 683
Income tax expense (benefit)	(22)	(188)	196
Net interest and other financing expense	174	166	282
Depreciation and amortization (a)	335	357	354
EBITDA	796	568	1,515
Income from discontinued operations (net of taxes)	(118)	(161)	(130)
Losses (gain) on pension and other postretirement plan remeasurement (b)	255	438	(417)
Net loss on divestitures	118	—	14
Restructuring and other integration costs	21	111	29
Tax indemnity income	(16)	—	—
Impairment of equity investments	14	50	—
Environmental reserve adjustments	12	13	16
Customer claim	13	—	—
Stock incentive award modification	7	—	—
Asset impairment and accelerated depreciation	6	36	2
Impairment of IPR&D assets	11	13	41
Foreign tax indemnification receivable adjustment	—	5	—
Legal reserve charge	—	5	—
Insurance settlement	—	—	(22)
Settled claim	—	—	(13)
Other	—	—	2
Adjusted EBITDA	$ 1,119	$ 1,078	$ 1,037

(a) Excludes $6 million, $36 million and $2 million of asset impairment charges and accelerated depreciation during 2015, 2014 and 2013, respectively.
(b) For supplemental information on the components of this adjustment, see page M-30 within the MD&A - Critical Accounting Policies - Employee benefit obligations.

Statements of Consolidated Comprehensive Income – caption review

A comparative analysis of the Statements of Consolidated Comprehensive Income by caption is provided as follows for the years ended September 30, 2015, 2014 and 2013.

(In millions)	2015	2014	2013	2015 change	2014 change
Sales	$ 5,387	$ 6,121	$ 6,091	$ (734)	$ 30

The following table provides a reconciliation of the change in sales between fiscal years 2015 and 2014 and between fiscal years 2014 and 2013.

(In millions)	2015 change	2014 change
Pricing	$ (166)	$ (88)
Volume and product mix	(19)	110
Currency exchange	(266)	8
Divestitures	(283)	—
Change in sales	$ (734)	$ 30

Sales for 2015 decreased $734 million, or 12%, compared to 2014 primarily due to the divestiture of certain divisions and product lines of $283 million, or 5%. The divestitures impact on sales was primarily due to the Elastomers division within the Performance Materials reportable segment. Unfavorable foreign currency exchange decreased sales by $266 million, or 4%, as a result of the U.S. dollar strengthening against foreign currencies, primarily the Euro. Additionally, pricing declines, primarily due to raw materials declines, across all reportable segments decreased sales by $166 million, or 3%, while volume and changes in product mix combined to decrease sales by $19 million, with the primary driver of the decline within Specialty Ingredients' energy market.

Sales for 2014 increased $30 million compared to 2013 primarily due to a combined change in volume and product mix which increased sales by $110 million, or 2%. Favorable currency exchange increased sales by $8 million. These increases were partially offset by pricing declines of $88 million, or 1%, primarily within the Performance Materials and Specialty Ingredients reportable segments.

(In millions)	2015	2014	2013	2015 change	2014 change
Cost of sales	$ 3,814	$ 4,605	$ 4,304	$ (791)	$ 301
Gross profit as a percent of sales	29.2%	24.8%	29.3%		

Fluctuations in cost of sales are driven primarily by raw material prices, volume and changes in product mix, currency exchange, losses or gains on pension and other postretirement benefit plan remeasurements, and other certain charges incurred as a result of changes or events within the businesses or restructuring activities.

The following table provides a reconciliation of the changes in cost of sales between fiscal years 2015 and 2014 and between fiscal years 2014 and 2013.

(In millions)	2015 change	2014 change
Production costs	$ (279)	$ (70)
Divestitures	(245)	—
Currency exchange	(181)	4
Volume and product mix	(30)	80
Pension and other postretirement benefit plans expense (income) (including remeasurements)	(43)	269
Asset impairment and accelerated depreciation	(30)	34
Inventory/customer claim charges	13	(51)
Severance and other costs	4	13
Insurance claim settlement	—	22
Change in cost of sales	$ (791)	$ 301

Cost of sales for 2015 decreased $791 million, or 17%, compared to 2014 primarily due to lower production costs, the divestiture of certain divisions and product lines, and favorable foreign currency exchange, which decreased cost of sales by $279 million, $245 million, and $181 million, respectively. The divestiture of the Elastomers division within the Performance Materials reportable segment accounted for $202 million, or 82%, of the $245 million divestiture impact on cost of sales. Volume and change in product mix combined also decreased cost of sales by $30 million. Pension and other postretirement plans expense decreased cost of sales by $43 million, primarily as a result of decreased remeasurement losses in 2015 compared to 2014, primarily due to lower than expected return on pension plan assets (see "Critical Accounting Policies" for additional details). The current year includes certain key items such as $17 million of severance and other costs and $6 million of accelerated depreciation related to a manufacturing facility within the Specialty Ingredients reportable segment, as well as $13 million in additional costs related to a customer claim.

The prior period includes certain key items such as $30 million of costs associated with plant closures within the Performance Materials reportable segment, which includes $17 million of accelerated depreciation, and also $19 million of asset impairment charges related to a foreign operation within the Specialty Ingredients reportable segment.

Cost of sales for 2014 increased $301 million, or 7%, compared to 2013 primarily due to increased expense of $269 million related to the pension and other postretirement plans' remeasurement losses in 2014 compared to a gain in 2013, which was primarily due to lower discount rates and a change in mortality tables (see "Critical Accounting Policies" for additional details). Lower production costs decreased cost of sales $70 million while higher volume and product mix resulted in an increase of $80 million. As previously discussed, cost of sales for 2014 also includes certain key items such as $49 million of costs associated with plant closures and a foreign operation. Cost of sales for 2013 included a $51 million inventory charge for certain guar-based products and inventory adjustments within Elastomers, a $22 million gain resulting from Ashland's settlement of an insurance claim, and $2 million of accelerated depreciation.

(In millions)	2015	2014	2013	2015 change	2014 change
Selling, general and administrative expense	$ 1,028	$ 1,358	$ 670	$ (330)	$ 688
As a percent of sales	19.1%	22.2%	11.0%		

Selling, general and administrative expense for 2015 decreased 24% compared to 2014, while expenses as a percent of sales decreased 3.1 percentage points. Key drivers of the fluctuation in selling, general and administrative expense compared to 2014 were:

- a $146 million decrease in expense compared to the prior year due to fluctuations in adjustments from the gains and losses for pension and postretirement benefit plans (costs of $155 million in 2015 and $301 million in 2014). As previously discussed within the cost of sales analysis, the 2015 remeasurement loss was driven primarily by a lower than expected return on pension plan assets (see "Critical Accounting Policies" for additional details);
- Approximately $100 million of current year cost savings related to the 2014 global restructuring compared to approximately $40 million of cost savings in the prior year;
- $98 million key item expense during 2014 for severance and other restructuring costs associated with the 2014 global restructuring;
- Environmental reserve expense adjustments of $32 million and $29 million during 2015 and 2014, respectively;
- Favorable foreign currency exchange of $36 million during 2015;
- Increased employee related costs of approximately $22 million during 2015;
- $21 million decrease in expense for certain divestitures, primarily the Elastomers division during 2015; and
- Tax indemnification income of $16 million and a stock incentive award modification resulting in expense of $7 million during 2015.

Selling, general and administrative expense for 2014 increased 103% compared to 2013, while expenses as a percent of sales increased 11.2 percentage points. Key drivers of the fluctuation in selling, general and administrative expense compared to 2013 were:

- a $590 million increase in expense compared to the prior year due to fluctuations in adjustments from the gains and losses for pension and postretirement benefit plans (cost of $301 million in 2014 and income of $289 million in 2013). As previously discussed within the cost of sales analysis, the 2014 remeasurement loss was driven primarily by lower discount rates and a change in mortality tables (see "Critical Accounting Policies" for additional details);
- Certain key item expense in 2014 and 2013 of $98 million and $29 million, respectively, for severance, restructuring and integration charges;
- Increased incentive compensation of approximately $50 million during 2014;
- Approximately $40 million in cost savings during 2014 resulting from the 2014 global restructuring program; and
- Environmental reserve expense adjustments of $29 million and $22 million during 2014 and 2013, respectively.

(In millions)	2015	2014	2013	2015 change	2014 change
Research and development expense	$ 110	$ 114	$ 142	$ (4)	$ (28)

Research and development expenses during 2015 decreased $4 million as compared to 2014. The current year includes an impairment of $11 million compared to $13 million in the prior year related to certain IPR&D assets associated with the acquisition of ISP.

Research and development expenses for 2014 decreased $28 million as compared to 2013. As noted previously, 2014 included an impairment related to certain IPR&D assets associated with the acquisition of ISP of $13 million compared to a $41 million impairment in 2013.

(In millions)	2015	2014	2013	2015 change	2014 change
Equity and other income (loss)					
Equity income (loss)	$ 1	$ (25)	$ 26	$ 26	$ (51)
Other income	22	27	38	(5)	(11)
	$ 23	$ 2	$ 64	$ 21	$ (62)

Total equity and other income increased $21 million during 2015 compared to 2014. Equity income increased $26 million in the current year primarily due to a $50 million impairment during the prior year related to the ASK joint venture equity investment within the Performance Materials reportable segment, partially offset by $10 million of lost income from the ASK joint venture as a result of its June 2014 sale. The current year included a $14 million impairment related to the Venezuelan joint venture equity investment within the Valvoline reportable segment. Other income in the prior year included income of $8 million from a favorable arbitration ruling on a commercial contract within the Valvoline reportable segment.

Total equity and other income decreased $62 million during 2014 compared to 2013. Equity income (loss) declined $51 million during 2014 primarily due to the $50 million impairment during the period within the ASK joint venture equity investment. The decrease in other income during 2014 is primarily due to a gain during 2013 of $13 million resulting from Ashland's settlement of a claim related to sales commissions and receivables within the Specialty Ingredients reportable segment. These decreases were partially offset by income of $8 million from a favorable arbitration ruling on a commercial contract within the Valvoline reportable segment during 2014.

(In millions)	2015	2014	2013	2015 change	2014 change
Net interest and other financing expense (income)					
Interest expense	$ 166	$ 163	$ 273	$ 3	$ (110)
Interest income	(6)	(6)	(4)	—	(2)
Available-for-sale securities income	(3)	—	—	(3)	—
Other financing costs	17	9	13	8	(4)
	$ 174	$ 166	$ 282	$ 8	$ (116)

Interest expense and other financing costs, excluding interest income and available-for-sale income, increased $11 million in 2015 compared to 2014. Excluding certain current year charges associated with the 2015 refinancing, interest expense remained relatively consistent with the prior year as generally lower interest rates offset higher debt levels during the year. As previously noted, 2015 included certain charges related to the 2015 refinancing. These included $2 million of accelerated amortization for previously capitalized debt issuance costs and $2 million of new debt issuance costs recognized immediately associated with the 2015 refinancing activities. Other financing costs included a $9 million charge related to the early redemption premium payment for the tender of the 2016 senior notes. The available-for-sale securities income of $3 million represents investment income related to the restricted investments discussed in Note F of the Notes to Consolidated Financial Statements.

Interest expense and other financing costs, excluding interest income, declined $114 million in 2014 compared to 2013. During 2013 there were significant charges included within the interest expense captions. Interest expense included a $47 million charge for the accelerated amortization of debt issuance and other costs resulting from the repayment of the 2011 Senior Credit Facility, as well as a $52 million charge resulting from the termination of the interest rate swap agreements associated with the 2011 Senior

Credit Facility. The 2013 period also included a $3 million charge for debt issuance costs and the original issue discount from certain instruments, as well as a $4 million charge related to an early redemption premium payment, both resulting from Ashland's repayment of the remaining 9.125% senior notes during 2013. Excluding these charges of $106 million during 2013, interest expense and other financing costs declined $8 million during 2014 primarily due to a lower outstanding debt balance for most of 2014 compared to 2013.

(In millions)	2015	2014	2013	2015 change	2014 change
Net gain (loss) on divestitures					
Elastomers	$ (86)	$ —	$ —	$ (86)	$ —
Valvoline car care products	(26)	—	—	(26)	—
MAP Transaction adjustments	(6)	4	(8)	(10)	12
PVAc divestiture	—	—	1	—	(1)
Other	3	—	(1)	3	1
	$ (115)	$ 4	$ (8)	$ (119)	$ 12

Net loss on divestitures during 2015 includes the pre-tax loss on sale related to Elastomers of $86 million, the $26 million impairment for the Valvoline car care products assets, and the $6 million reduction related to the 2005 transfer of Ashland's 38% interest in the Marathon Ashland Petroleum joint venture and two other small businesses to Marathon Oil Corporation (Marathon) (the MAP Transaction) receivable, primarily due to the January 2015 asbestos insurance settlement.

Net gain on divestitures during 2014 includes a gain resulting from the receipt of a tax credit reimbursement and other subsequent adjustments related to the MAP Transaction for certain state tax attributes.

Net loss on divestitures during 2013 includes a $14 million expense settlement and several favorable tax adjustments related to the MAP Transaction.

(In millions)	2015	2014	2013	2015 change	2014 change
Income tax expense (benefit)	$ (22)	$ (188)	$ 196	$ 166	$ (384)
Effective tax rate	(13)%	(162)%	26%		
Effective tax rate (excluding key items)	23 %	20 %	22%		

The fiscal 2015 effective tax rate was impacted by net favorable items predominantly due to certain valuation allowance releases related to state deferred tax assets. These favorable adjustments were partially offset by an accrual for an unrecognized tax benefit and tax related to certain global restructuring steps.

Income tax benefit for 2014 included a $168 million tax benefit related to the reversal of deferred tax liabilities for outside basis differences and other related matters, a charge of $39 million for taxes associated with the sale of shares of subsidiaries included in the sale of the Water Technologies business, net charges of $32 million for uncertain tax positions and related matters, a charge of $14 million for a foreign income tax rate change and other net discrete item charges of $7 million primarily related to changes in valuation allowances. During the quarter ended September 30, 2014, as a result of an updated analysis of future cash needs in the U.S. and opportunities for investment outside the U.S., including the use of proceeds from the Water Technologies sale, Ashland changed its assertion related to the historical earnings of certain subsidiaries, and reversed deferred tax liabilities of $168 million (as noted previously), resulting in a tax benefit in 2014.

Income tax expense for 2013 included a zero benefit recorded on the MAP Transaction charge of $14 million and a net benefit of $16 million primarily attributable to a foreign income tax rate change.

(In millions)	2015	2014	2013	2015 change	2014 change
Income (loss) from discontinued operations					
(net of taxes)					
Asbestos-related litigation matters	$ 110	$ 6	$ 2	$ 104	$ 4
Water Technologies	6	151	124	(145)	27
Distribution	1	—	(6)	1	6
APAC	1	4	10	(3)	(6)
	$ 118	$ 161	$ 130	$ (43)	$ 31

The current year included an after-tax gain of $120 million related to the January 2015 asbestos insurance settlement, partially offset by after-tax net expense adjustments to the asbestos reserves and receivables, including the adjustments for changes in estimates as well as a deferred tax adjustment. The results for income from discontinued operations for 2014 and 2013 also includes favorable net adjustments (after-tax) to the asbestos reserve and related receivables of $6 million and $2 million during 2014 and 2013, respectively.

Water Technologies activity during 2015 related primarily to income of $5 million due to a foreign pension plan remeasurement discussed in Note M in Notes to Consolidated Financial Statements as well as other post-closing adjustments. The 2014 period includes an after-tax gain of $92 million on the sale of Water Technologies and ten months of Water Technologies' operating results as compared to a full year of operating results for 2013 as a result of the July 31, 2014 sale of the Water Technologies business to CD&R. Water Technologies sales for 2014 and 2013 included in discontinued operations were $1,475 million and $1,722 million, respectively. Gross profit margin, on a comparable and adjusted basis, was 35.0% and 33.7%, respectively. On a comparable and adjusted basis the operating income for Water Technologies during 2014 and 2013 was $111 million and $92 million, respectively.

The reported results for Water Technologies in 2014 included $29 million from depreciation and amortization that was recorded before the announced definitive agreement signed in February 2014. Due to Water Technologies designation as held for sale within the Consolidated Balance Sheets, no future depreciation or amortization was recorded. Additionally, 2014 and 2013 reported results included a loss of $19 million and a gain of $81 million, respectively for pension and other postretirement plan remeasurement net losses or gains, which is discussed further in Note M of the Notes to the Consolidated Financial Statements. Also, 2013 included an $11 million charge for restructuring.

The operational results for income from discontinued operations for 2015, 2014 and 2013 also include subsequent environmental and tax adjustments to the previously divested businesses of Ashland Distribution (Distribution) and Ashland Paving And Construction, Inc. (APAC).

Other comprehensive income (loss)

A comparative analysis of the components of other comprehensive income (loss) is provided below for the last three fiscal years ended September 30.

(In millions)	2015	2014	2013	2015 change	2014 change
Other comprehensive income (loss)					
(net of taxes)					
Unrealized translation gain (loss)	$ (369)	$ (160)	$ 37	$ (209)	$ (197)
Pension and postretirement obligation adjustment	(18)	(21)	(5)	3	(16)
Unrealized loss on available-for-sale securities	(11)	—	—	(11)	—
Net change in interest rate hedges	—	—	38	—	(38)
	$ (398)	$ (181)	$ 70	$ (217)	$ (251)

Total other comprehensive loss, net of tax, decreased $217 million in 2015 as compared to 2014 as a result of the following components.

- In 2015, other comprehensive loss, net of tax, from foreign currency translation adjustments was $369 million, compared to $160 million in 2014, mainly as a result of the strengthening of the U.S. Dollar against other global currencies, including the Euro and Australian dollar. The fluctuations in unrealized translation losses are primarily due to translating foreign subsidiary financial statements from local currencies to U.S. Dollars.

- Pension and postretirement obligation adjustment was $18 million and $21 million in 2015 and 2014, respectively. Of these amounts, $17 million and $25 million during 2015 and 2014, respectively, of unrecognized prior service credits, net of tax, related to pension and other postretirement benefit plans were amortized and reclassified into net income, while cost of $1 million and credit of $4 million, respectively, of additional unrecognized prior service, net of tax, was included in other comprehensive loss.
- $11 million of unrealized loss on available-for-sale securities, net of tax, related to the restricted investments, was recognized within other comprehensive loss during 2015.

Total other comprehensive income (loss), net of tax, decreased $251 million in 2014 as compared to 2013 as a result of the following components.

- In 2014, other comprehensive loss, net of tax, from foreign currency translation adjustments was $160 million, of which $166 million was recognized within other comprehensive income during 2014, compared to a gain of $37 million in 2013. The fluctuations in unrealized translation are primarily due to translating foreign subsidiary financial statements from local currencies to U.S. Dollars. The change in this caption is a result of the U.S. dollar strengthening against the Euro during the last quarter of 2014. Additionally, as a result of the sale of Water Technologies during 2014, $6 million of translation losses were reclassified into net income.
- Pension and postretirement obligation adjustment was $21 million and $5 million in 2014 and 2013, respectively. Of these amounts, $25 million and $15 million during 2014 and 2013, respectively, of unrecognized prior service credits, net of tax, related to pension and other postretirement benefit plans were amortized and reclassified into net income, while $4 million and $10 million, respectively, of additional unrecognized prior service credit, net of tax, was included in other comprehensive income (loss).
- During 2013, $38 million of a net change related to interest rate hedges was recognized. Of this amount, $41 million, net of tax, was reclassified into net income for losses related to the interest rate hedges terminated during the year, while $3 million of an unrealized loss was recorded prior to the termination.

RESULTS OF OPERATIONS – REPORTABLE SEGMENT REVIEW

Subsequent to the sale of Water Technologies and a business realignment during 2014, Ashland's businesses are managed within three reportable segments: Specialty Ingredients, Performance Materials and Valvoline.

The 2014 business realignment resulted in the re-organization of Specialty Ingredients into two divisions: Consumer Specialties and Industrial Specialties, with the adhesives category joining the Industrial Specialties division, moving over from Performance Materials. While, Performance Materials became comprised of three divisions: 1) Intermediates/Solvents, which moved over from Specialty Ingredients and serves both Ashland's internal butanediol needs as well as the merchant market; 2) Composites, which serves construction, transportation, marine and other markets; and 3) Elastomers, which primarily served the North American replacement tire market prior to its December 1, 2014 sale. The business realignment during 2014 did not affect the Valvoline business, as it remained unchanged compared to prior year periods.

Results of Ashland's reportable segments are presented based on its management structure and internal accounting practices. The structure and practices are specific to Ashland; therefore, the financial results of Ashland's reportable segments are not necessarily comparable with similar information for other comparable companies. Ashland allocates all costs to its reportable segments except for certain significant company-wide restructuring activities, such as certain restructuring plans described in Note E of Notes to Consolidated Financial Statements, and other costs or adjustments that relate to former businesses that Ashland no longer operates. The service cost component of pension and other postretirement benefits costs is allocated to each reportable segment on a ratable basis; while the remaining components of pension and other postretirement benefits costs are recorded to Unallocated and other. Ashland refines its expense allocation methodologies to the reportable segments from time to time as internal accounting practices are improved, more refined information becomes available and the industry or market changes. Revisions to Ashland's methodologies that are deemed insignificant are applied on a prospective basis.

The EBITDA and Adjusted EBITDA amounts presented within this business section are provided as a means to enhance the understanding of financial measurements that Ashland has internally determined to be relevant measures of comparison for each reportable segment. Each of these non-GAAP measures is defined as follows: EBITDA (operating income plus depreciation and amortization), Adjusted EBITDA (EBITDA adjusted for key items, which may include pro forma effects for significant acquisitions or divestitures, as applicable), and Adjusted EBITDA margin (Adjusted EBITDA, which may include pro forma adjustments, divided by sales or sales adjusted for pro forma results). Ashland does not allocate items to each reportable segment below operating income, such as interest expense and income taxes. As a result, reportable segment EBITDA and Adjusted EBITDA are reconciled directly to operating income since it is the most directly comparable U.S. GAAP measure.

The following table shows sales, operating income and statistical operating information by reportable segment for each of the last three years ended September 30.

(In millions)	2015	2014	2013
Sales			
Specialty Ingredients	$ 2,263	$ 2,498	$ 2,478
Performance Materials	1,157	1,582	1,617
Valvoline	1,967	2,041	1,996
	$ 5,387	$ 6,121	$ 6,091
Operating income (loss)			
Specialty Ingredients	$ 239	$ 253	$ 243
Performance Materials	87	7	106
Valvoline	359	323	295
Unallocated and other	(227)	(537)	395
	$ 458	$ 46	$ 1,039
Depreciation and amortization			
Specialty Ingredients	$ 244	$ 262	$ 242
Performance Materials	59	91	75
Valvoline	38	37	35
Unallocated and other	—	3	4
	$ 341	$ 393	$ 356
Operating information			
Specialty Ingredients (a)			
Sales per shipping day	$ 8.9	$ 9.9	$ 9.8
Metric tons sold (thousands)	324.3	355.2	336.1
Gross profit as a percent of sales	32.4%	31.2%	30.8%
Performance Materials (a)			
Sales per shipping day	$ 4.6	$ 6.3	$ 6.4
Metric tons sold (thousands)	476.6	591.1	582.8
Gross profit as a percent of sales	18.8%	13.1%	14.9%
Valvoline (a)			
Lubricant sales gallons	167.4	162.6	158.4
Premium lubricants (percent of U.S. branded volumes)	40.2%	37.1%	33.6%
Gross profit as a percent of sales	35.6%	31.8%	31.6%

(a) Sales are defined as sales and operating revenues. Gross profit is defined as sales, less cost of sales.

Sales by region expressed as a percentage of reportable segment sales for each of the last three fiscal years ended September 30 were as follows. Ashland includes only U.S. and Canada in its North American designation.

	2015		
Sales by Geography	Specialty Ingredients	Performance Materials	Valvoline
North America	39%	43%	73%
Europe	32%	37%	8%
Asia Pacific	19%	14%	14%
Latin America & other	10%	6%	5%
	100%	100%	100%

	2014		
Sales by Geography	Specialty Ingredients	Performance Materials	Valvoline
North America	39%	48%	72%
Europe	33%	33%	9%
Asia Pacific	18%	14%	14%
Latin America & other	10%	5%	5%
	100%	100%	100%

	2013		
Sales by Geography	Specialty Ingredients	Performance Materials	Valvoline
North America	42%	48%	73%
Europe	31%	34%	9%
Asia Pacific	17%	12%	14%
Latin America & other	10%	6%	4%
	100%	100%	100%

Specialty Ingredients

Specialty Ingredients is a global leader in cellulose ethers, vinyl pyrrolidones and biofunctionals. It offers industry-leading products, technologies and resources for solving formulation and product-performance challenges. Specialty Ingredients uses natural, synthetic and semisynthetic polymers derived from plant and seed extract, cellulose ethers, vinyl pyrrolidones, acrylic polymers as well as polyester and polyurethane-based adhesives. Specialty Ingredients includes two divisions, Consumer Specialties and Industrial Specialties, that offer comprehensive and innovative solutions for today's demanding consumer and industrial applications. Key customers include: pharmaceutical companies; makers of personal care products, food and beverages; manufacturers of paint, coatings and construction materials; packaging and converting; and oilfield service companies.

During 2015, Ashland sold the industrial biocides assets within Specialty Ingredients. For additional information on this divestiture, see the "Key Developments" section of Management's Discussion and Analysis herein.

2015 compared to 2014

Specialty Ingredients' sales decreased $235 million, or 9%, to $2,263 million in 2015. Energy market sales decreased $106 million compared to the prior year primarily due to lower volume, in part due to the exit of the straight guar powder market. Excluding this effect of the energy market, sales decreased by $129 million with unfavorable foreign currency exchange decreasing sales by $105 million due to the U.S. dollar strengthening compared to various foreign currencies. Pricing declines, the exit from the redispersible powders product line and the divestiture of the industrial biocides assets decreased sales by $27 million, $19 million and $11 million, respectively, while changes in volume and product mix increased sales by $33 million.

Gross profit during 2015 decreased $47 million compared to 2014. The current year includes $17 million of severance and other costs, $6 million of accelerated depreciation relating to a manufacturing facility restructuring plan and a $13 million charge related to a customer claim, while the prior year included a $19 million impairment charge related to a foreign operation. Gross profit decreased $22 million compared to the prior year primarily driven by lower volumes for customers within the energy market. Excluding the energy market and the costs noted previously, gross profit decreased by $8 million compared to 2014. Unfavorable foreign currency exchange decreased gross profit by $51 million as the U.S. dollar strengthened compared to various foreign currencies. Favorable costs, primarily due to lower raw material costs, were partially offset by pricing declines, and increased gross profit by $23 million while volume and product mix combined to increase gross profit by $20 million. In total, gross profit margin during 2015 increased 1.2 percentage points as compared to 2014 to 32.4%.

Selling, general and administrative expense (which includes research and development expenses throughout the reportable segment discussion and analysis) decreased $33 million, or 6%, during 2015 as compared to 2014. This decrease was primarily due to $41 million expense savings realized from the 2014 global restructuring program and a favorable foreign currency exchange of $22 million. Additionally, research and development expenses decreased $2 million compared to the prior year as the current and prior year included $11 million and $13 million of noncash impairments related to certain IPR&D assets, respectively. These decreases were partially offset by increased general company allocated resource costs of $21 million and increased employee benefit costs of $4 million. The current year also included a $3 million environmental charge compared to $1 million in the prior year. Equity and other income remained consistent with the prior year.

Operating income totaled $239 million for 2015 compared to $253 million in 2014. EBITDA decreased $19 million to $477 million in 2015. Adjusted EBITDA decreased $2 million to $527 million in 2015. Adjusted EBITDA margin increased 2.1 percentage points in 2015 to 23.3%.

2014 compared to 2013

Specialty Ingredients' sales increased $20 million, or 1%, to $2,498 million in 2014. Excluding the effect of guar products, sales increased by $85 million with volume and mix combined increasing sales by $80 million and currency exchange increasing sales by $19 million. These increases were partially offset by pricing which decreased sales by $14 million. Guar product sales decreased $65 million compared to 2013 as guar powder sales declined by $77 million.

Gross profit during 2014 increased $16 million compared to 2013. Gross profit in 2014 included a $19 million impairment charge related to a foreign operation. Gross profit in 2013 included a $31 million loss on guar inventory, as well as a $22 million gain resulting from Ashland's settlement of an insurance claim. Volume and product mix combined to increase gross profit by $17 million while improved sales pricing compared to costs resulted in a net favorable impact of $2 million. In addition, favorable currency exchange increased gross profit by $7 million. In total, gross profit margin during 2014 increased 0.4 percentage points as compared to 2013 to 31.2%.

Selling, general and administrative expense decreased $12 million, or 2%, during 2014 as compared to 2013. Research and development expenses decreased by $27 million primarily due to 2013 including $41 million of noncash impairment charges related to certain IPR&D assets compared to $13 million in 2014. This decrease was partially offset by increased general company allocated resource costs of $14 million. Equity and other income decreased $18 million in 2014 compared to 2013 primarily due to income of $13 million recorded during 2013 to resolve a claim, as well as $5 million of a decrease in equity income and other items.

Operating income totaled $253 million during 2014 compared to $243 million in 2013. EBITDA increased $11 million to $496 million in 2014. Adjusted EBITDA increased $38 million to $529 million in 2014. Adjusted EBITDA margin increased 1.4 percentage points in 2014 to 21.2%.

EBITDA and Adjusted EBITDA reconciliation

The following EBITDA and Adjusted EBITDA presentation for the three annual periods is provided as a means to enhance the understanding of financial measurements that Ashland has internally determined to be relevant measures of comparison for the results of Specialty Ingredients. Adjusted EBITDA results have been prepared to illustrate the ongoing effects of Ashland's operations, which exclude certain key items such as the $17 million of severance and other costs related to a manufacturing facility restructuring plan during the current year. The impairments of $11 million during 2015, $13 million during 2014, and $41 million during 2013 relate to certain IPR&D assets associated with the acquisition of ISP during 2011. The $19 million charge during 2014 related to the impairment of a foreign operation while the $6 million of accelerated depreciation in the current year relates to a manufacturing facility restructuring plan. The $13 million adjustments during 2015 and 2013 related to a customer claim and Ashland's settlement of a customer claim, respectively, during each fiscal year and the $22 million adjustment during 2013 related to a gain resulting from Ashland's settlement of an insurance claim.

	September 30		
(In millions)	2015	2014	2013
Operating income	$ 239	$ 253	$ 243
Depreciation and amortization (a)	238	243	242
EBITDA	477	496	485
Severance and other costs	17	—	—
Impairment of IPR&D assets	11	13	41
Customer claim	13	—	—
Accelerated depreciation and asset impairment	6	19	—
Environmental reserve adjustment	3	1	—
Insurance settlement	—	—	(22)
Settled claim	—	—	(13)
Adjusted EBITDA	$ 527	$ 529	$ 491

(a) Excludes $6 million and $19 million of accelerated depreciation and asset impairment charges during 2015 and 2014, respectively.

Performance Materials

Performance Materials is a global leader in unsaturated polyester resins and vinyl ester resins. The business unit has leading positions in gelcoats, maleic anhydride, butanediol, tetrahydrofuran, N-Methylpyrrolidone and other intermediates and solvents. Key customers include: manufacturers of residential and commercial building products; industrial product specifiers and manufacturers; wind blade and pipe manufacturers; automotive and truck OEM suppliers; boatbuilders; engineered plastics and electronic producers; and specialty chemical manufacturers.

Performance Materials is composed of two divisions: Composites and Intermediates/Solvents. Results from the former Elastomers division, which primarily served the North American replacement tire market, accounted for approximately 18% of Ashland Performance Materials' $1.6 billion in sales in 2014 and operated a 250-person manufacturing facility in Port Neches, Texas. Elastomers results were included in the Performance Materials reportable segment results of operations within the Statements of Consolidated Comprehensive Income until its December 1, 2014 sale.

For additional information on the divestiture of the Elastomers division, see the "Key Developments" section of Management's Discussion and Analysis herein.

2015 compared to 2014

Performance Materials' sales decreased $425 million, or 27%, to $1,157 million in 2015. The divestiture of the Elastomers division decreased sales by $237 million, or 15%. Unfavorable foreign currency exchange and lower product pricing within both Composites and Intermediates/Solvents divisions decreased sales by $87 million, or 5%, and $81 million, or 5%, respectively. Unfavorable foreign currency exchange was due to the U.S. dollar strengthening compared to various foreign currencies, primarily the Euro. Volume and changes in product mix decreased sales by $13 million and $7 million, respectively.

Gross profit increased $10 million in 2015 compared to 2014. The prior year included $30 million of costs associated with plant closures resulting from the 2014 global restructuring program as well as $35 million of gross profit related to the Elastomers division. The current year was negatively impacted by plant maintenance shutdowns at both Intermediates/Solvents manufacturing facilities which resulted in a $14 million decrease in gross profit. Excluding the impact of these shutdowns, lower input costs, partially offset by pricing declines, within both Composites and Intermediates/Solvents combined to increase gross profit by $55 million. Unfavorable currency exchange, driven by the U.S. dollar strengthening compared to certain foreign currencies, and changes in volume and product mix combined to decrease gross profit by $14 million and $12 million, respectively. In total, gross profit margin during 2015 increased 5.7 percentage points as compared to 2014 to 18.8%.

Selling, general and administrative expense decreased $30 million, or 18%, during 2015 compared to 2014, primarily due to the sale of the Elastomers division, which included $19 million of costs in the prior year, as well as $4 million in expense savings realized from the 2014 global restructuring program, and favorable foreign currency exchange of $5 million. These decreases were partially offset by an increase in incentive compensation. The prior year also included a $5 million legal reserve charge.

Equity and other income increased $40 million during 2015 compared to 2014, primarily due to a $50 million impairment for the ASK joint venture equity investment during the prior year, partially offset by a $10 million decrease due to the loss of equity income from the ASK joint venture as a result of its June 2014 sale.

Operating income totaled $87 million in 2015 compared to $7 million in 2014. EBITDA increased $65 million to $146 million in 2015. Adjusted EBITDA decreased $20 million to $146 million in 2015. Adjusted EBITDA margin increased 2.1 percentage points to 12.6% in 2015.

2014 compared to 2013

Performance Materials' sales decreased $35 million, or 2%, to $1,582 million in 2014. Lower product pricing decreased sales $41 million, or 3%, and changes in product mix decreased sales by $11 million. Volume increased sales by $17 million as metric tons sold increased to 591.1 thousand metric tons.

Gross profit decreased $34 million in 2014 compared to 2013. Both 2014 and 2013 included $30 million and $2 million, respectively, of costs associated with plant closures. The prior year plant closure costs are associated with the global restructuring program implemented in 2014, while the 2013 plant closure charges were incurred as part of the ongoing stranded cost and ISP integration programs. In addition, 2013 included a $20 million inventory charge in the Elastomers division. Pricing declines during 2014, primarily within the Intermediates/Solvents division, reduced gross profit by $25 million. Volume and changes in product mix combined to decrease gross profit by $2 million, while favorable currency exchange increased gross profit by $1 million. In total, gross profit margin during 2014 increased 1.8 percentage points as compared to 2013 to 13.1%.

Selling, general and administrative expense increased $16 million, or 11%, during 2014 compared to 2013, primarily due to increased incentive compensation of $5 million and general company allocated resource costs of $9 million, as well as a $5 million legal reserve charge, partially offset by decreases in employee expenses of $3 million. Equity and other income decreased $49

million during 2014 compared to 2013, primarily due to a $50 million impairment charge for the ASK joint venture equity investment during 2014.

Operating income totaled $7 million in 2014 compared to $106 million in 2013. EBITDA decreased $98 million to $81 million in 2014. Adjusted EBITDA decreased $15 million to $166 million in 2014. Adjusted EBITDA margin decreased 0.7 percentage points to 10.5% in 2014.

Out-of-Period Adjustments

In fiscal year 2013, Ashland identified an error in the application of lower-of-cost-or-market ("LCM") valuation principles to the inventory of the Elastomers division. As a result, fiscal year 2013 results included out-of-period inventory valuation charges related to the Elastomers division of approximately $20 million, of which $8 million related to fiscal year 2013 and $12 million related to fiscal year 2012. Ashland concluded that the out-of-period inventory valuation charges related to the Elastomers division were immaterial when considered from both a quantitative and a qualitative perspective.

EBITDA and Adjusted EBITDA reconciliation

The following EBITDA and Adjusted EBITDA presentation for the three annual periods is provided as a means to enhance the understanding of financial measurements that Ashland has internally determined to be relevant measures of comparison for the results of Performance Materials. Adjusted EBITDA results have been prepared to illustrate the ongoing effects of Ashland's operations, which exclude certain key items such as the $50 million charge during 2014 related to the impairment of the ASK joint venture equity investment. The $13 million and $17 million of severance and accelerated depreciation, respectively, during 2014 related to the 2014 global restructuring program. The $2 million of accelerated depreciation and other plant closure costs in 2013 were incurred as part of the ongoing stranded cost and ISP integration programs. The $5 million during 2014 relates to a legal reserve charge.

	September 30		
(In millions)	2015	2014	2013
Operating income	$ 87	$ 7	$ 106
Depreciation and amortization (a)	59	74	73
EBITDA	146	81	179
Impairment of equity investment	—	50	—
Severance	—	13	—
Legal reserve charge	—	5	—
Accelerated depreciation	—	17	2
Adjusted EBITDA	$ 146	$ 166	$ 181

(a) Excludes $17 million and $2 million of accelerated depreciation during 2014 and 2013, respectively.

Valvoline

Valvoline is a leading, worldwide producer and distributor of premium-branded automotive, commercial and industrial lubricants and automotive chemicals. It ranks as the #2 quick-lube chain and #3 passenger car motor oil brand in the United States. The brand operates and franchises approximately 940 Valvoline Instant Oil Change℠ centers in the United States. It also markets Valvoline™ lubricants and automotive chemicals; MaxLife™ lubricants created for higher-mileage engines; SynPower™ synthetic motor oil; and Zerex™ antifreeze. Key customers include: retail auto parts stores and mass merchandisers who sell to consumers; installers, such as car dealers, repair shops and quick lubes; commercial fleets; and distributors.

During 2015, Ashland sold its Valvoline car care product assets, including Car Brite™ and Eagle One™ automotive appearance products, and sold its joint venture equity investment within Venezuela. Additionally during 2015, Ashland announced a plan to separate Valvoline. The separation is expected to be completed as soon as practicable, but not before the end of fiscal 2016. For additional information on the divestitures, see the "Key Developments" section of Management's Discussion and Analysis herein.

2015 compared to 2014

Valvoline's sales decreased $74 million, or 4%, to $1,967 million in 2015. Unfavorable foreign currency exchange and lower product pricing decreased sales by $70 million, or 3%, and $53 million, or 3%, respectively. Unfavorable foreign currency exchange was due to the U.S. dollar strengthening compared to various foreign currencies, primarily the Euro and Australian dollar. Higher volume levels and changes in product mix increased sales by $55 million, or 3%, and $10 million, respectively. The divestiture of Valvoline car care product assets on June 30, 2015 decreased sales by $16 million compared to the prior year.

Gross profit increased $51 million during 2015 compared to 2014. Lower raw material costs, partially offset by lower product pricing, increased gross profit by $52 million. Changes in volume and product mix combined to increase gross profit by $20 million, while unfavorable foreign currency exchange decreased gross profit by $18 million. The divestiture of Valvoline car care product assets also decreased gross profit by $3 million. In total, gross profit margin during 2015 increased 3.8 percentage points to 35.6%.

Selling, general and administrative expense decreased $7 million, or 2%, during 2015 as compared to 2014, primarily as a result of $20 million of cost savings from the 2014 global restructuring as well as declines from favorable foreign currency exchange of $9 million. These decreases were partially offset by increased employee and general company allocated resource costs of $9 million, as well as legal and technology expenses of $5 million and advertising costs of $5 million.

Equity and other income decreased by $22 million during 2015 compared to 2014, primarily due to an $8 million favorable arbitration ruling on a commercial contract in the prior year and the $14 million impairment of a joint venture equity investment within Venezuela in the current year. For additional information see Note B in the Notes to Condensed Consolidated Financial Statements.

Operating income totaled $359 million in 2015 as compared to $323 million in 2014. EBITDA increased $37 million to $397 million in 2015. Adjusted EBITDA increased $51 million to $411 million in 2015. Adjusted EBITDA margin increased 3.3 percentage points to 20.9% in 2015.

2014 compared to 2013

Valvoline's sales increased $45 million, or 2%, to $2,041 million in 2014. Volume increased sales by $37 million, or 2%, as lubricant gallons sold increased to 162.6 million gallons during 2014. Changes in product mix and improved pricing increased sales by $15 million and $4 million, respectively. Unfavorable currency exchange decreased sales $11 million.

Gross profit increased $17 million during 2014 compared to 2013. Changes in volume and product mix combined to increase gross profit by $16 million, while price improvements increased gross profit by $4 million. The currency exchange effect during the year reduced gross profit by $3 million. In total, gross profit margin during 2014 increased 0.2 percentage points to 31.8%.

Selling, general and administrative expense decreased $5 million, or 1%, during 2014 as compared to 2013, primarily as a result of decreased advertising and promotional expenses of $13 million, partially offset by increased general company allocated resource costs of $8 million. Equity and other income increased by $6 million during 2014 compared to 2013, primarily due to a favorable arbitration ruling on a commercial contract during 2014.

Operating income totaled $323 million in 2014 as compared to $295 million in 2013. EBITDA increased $30 million to $360 million in 2014. EBITDA margin increased 1.1 percentage points to 17.6% in 2014. There were no unusual or key items that affected comparability for EBITDA during 2014 and 2013.

EBITDA and Adjusted EBITDA reconciliation

The following EBITDA and Adjusted EBITDA presentation for the three annual periods is provided as a means to enhance the understanding of financial measurements that Ashland has internally determined to be relevant measures of comparison for the results of Valvoline. Adjusted EBITDA results have been prepared to illustrate the ongoing effects of Ashland's operations, which exclude certain key items. The $14 million adjustment in the current year related to the impairment of a joint venture equity investment within Venezuela. There were no unusual or key items that affected comparability for Adjusted EBITDA during 2014 and 2013.

	September 30		
(In millions)	2015	2014	2013
Operating income	$ 359	$ 323	$ 295
Depreciation and amortization	38	37	35
EBITDA	397	360	330
Impairment of equity investment	14	—	—
Adjusted EBITDA	$ 411	$ 360	$ 330

Unallocated and other

The following table summarizes the key components of the Unallocated and other segment's operating income (loss) for each of the last three years ended September 30.

(In millions)	September 30 2015	2014	2013
Gain (losses) on pension and other postretirement plan remeasurement	$ (255)	$ (438)	$ 417
Pension and other postretirement net periodic income (a)	54	54	68
Restructuring activities (includes stranded costs from Water Technologies)	(8)	(129)	(64)
Environmental reserves for divested businesses	(29)	(28)	(22)
Tax indemnity income	16	—	—
Other income (expense)	(5)	4	(4)
Total unallocated income (expense)	$ (227)	$ (537)	$ 395

(a) Amounts exclude service costs of $27 million during 2015 and $30 million during each of 2014 and 2013 which are allocated to Ashland's reportable segments.

Unallocated and other recorded expense of $227 million for 2015, expense of $537 million for 2014, and income of $395 million for 2013. Unallocated and other includes pension and other postretirement net periodic costs and income within continuing operations that have not been allocated to reportable segments. These costs include interest cost, expected return on assets and amortization of prior service credit, which resulted in income of $54 million during each of 2015 and 2014, and $68 million in 2013. Unallocated and other also includes gains and losses on pension and other postretirement plan remeasurements, which resulted in a loss of $255 million in 2015, a loss of $438 million in 2014, and a gain of $417 million in 2013. Fluctuations in these amounts from year to year result primarily from changes in the discount rate but are also partially affected by differences between the expected and actual return on plan assets during each year as well as other changes in other actuarial assumptions such as changes in demographic data or mortality assumptions. For additional information regarding the actual remeasurement for certain key assumptions for each year, see MD&A - Critical Accounting Policies - Employee benefit obligations and Note M of Notes to Consolidated Financial Statements.

Unallocated and other also includes restructuring expense of $8 million, $98 million, and $30 million during 2015, 2014, and 2013, respectively, primarily related to severance programs as well as certain indirect corporate costs of $31 million and $34 million in 2014 and 2013, respectively, previously allocated to the Water Technologies business. Restructuring expense in 2015 and 2014 was associated with the 2014 global restructuring program while 2013 related primarily to certain severance programs and other ISP integration activities.

Additionally, unallocated and other includes environmental charges related to previously divested businesses of $29 million, $28 million and $22 million during 2015, 2014, and 2013, respectively. The current year also includes $16 million of tax indemnity income and expense of $7 million for the stock incentive plan award modification.

FINANCIAL POSITION

Liquidity

Ashland had $1,257 million in cash and cash equivalents as of September 30, 2015, of which $1,223 million was held by foreign subsidiaries and had no significant limitations that would prohibit remitting the funds to satisfy corporate obligations. However, if this amount was repatriated to the United States, additional taxes would likely need to be accrued and paid depending upon the source of the earnings remitted. Ashland currently has no plans to repatriate any amounts for which additional U.S. taxes would need to be accrued.

Ashland's cash flows from operating, investing and financing activities, as reflected in the Statements of Consolidated Cash Flows, are summarized as follows.

(In millions)	2015	2014	2013
Cash provided (used) by:			
Operating activities from continuing operations	$ 89	$ 580	$ 653
Investing activities from continuing operations	(417)	(168)	(272)
Financing activities from continuing operations	(30)	(1,034)	(592)
Discontinued operations	269	1,671	32
Effect of currency exchange rate changes on cash and cash equivalents	(47)	(2)	2
Net increase (decrease) in cash and cash equivalents	$ (136)	$ 1,047	$ (177)

Ashland paid income taxes of $226 million during 2015 compared to $88 million in 2014 and $69 million in 2013. Cash receipts for interest income were $6 million in each of 2015 and 2014, and $4 million in 2013, while cash payments for interest expense amounted to $149 million in 2015, $154 million in 2014 and $182 million in 2013. Foreign currency exchange had an unfavorable impact on cash and cash equivalents during 2015 primarily as a result of the strengthening of the U.S. dollar compared to foreign currencies, primarily the Euro.

Operating activities

The following discloses the cash flows associated with Ashland's operating activities for 2015, 2014 and 2013, respectively.

(In millions)	2015	2014	2013
Cash flows provided (used) by operating activities from continuing operations			
Net income	$ 309	$ 233	$ 683
Income from discontinued operations (net of taxes)	(118)	(161)	(130)
Adjustments to reconcile income from continuing operations to cash flows from operating activities			
Depreciation and amortization	341	393	356
Debt issuance cost amortization	18	14	65
Deferred income taxes	(57)	(294)	153
Equity income from affiliates	(15)	(25)	(26)
Distributions from equity affiliates	22	14	11
Stock based compensation expense - Note P	30	34	30
Loss on early retirement of debt	9	—	—
Gain on available-for-sale securities	(3)	—	—
Net loss (gain) on divestitures - Note B	115	(4)	8
Impairments of equity investments and in-process research and development	25	63	41
Pension contributions	(610)	(38)	(124)
Losses (gain) on pension and postretirement plan remeasurement	255	438	(417)
Change in operating assets and liabilities (a)	(232)	(87)	3
Total cash flows provided by operating activities from continuing operations	$ 89	$ 580	$ 653

(a) Excludes changes resulting from operations acquired or sold.

Cash flows generated from operating activities from continuing operations, a major source of Ashland's liquidity, amounted to $89 million in 2015, $580 million in 2014 and $653 million in 2013. The cash generated during each period is primarily driven by net income results, excluding results from discontinued operations, and adjusted for certain non-cash items such as depreciation and amortization (including debt issuance cost amortization) and remeasurement adjustments to the pension and other postretirement plans, as well as changes in working capital, which are fluctuations within accounts receivable, inventory, and trade and other payables. Ashland continues to emphasize working capital management as a high priority and focus.

The significant decline in operating cash flow during the current year related primarily to $610 million of pension contributions, which includes the $500 million voluntary pension plan contribution made during 2015 for plans impacted by the pension plan settlement program. See Note M in Notes to Consolidated Financial Statements for further information. Operating cash flows for 2014 and 2013 also included pension contributions of $38 million and $124 million, respectively.

The following details certain changes in key operating assets and liabilities for 2015, 2014 and 2013, respectively.

(In millions)	2015	2014	2013
Changes in assets and liabilities (a)			
Accounts receivable	$ 261	$ (16)	$ 43
Inventories	39	(4)	106
Trade and other payables	(229)	64	(7)
Other assets and liabilities	(303)	(131)	(139)
Change in operating assets and liabilities	$ (232)	$ (87)	$ 3

(a) Excludes changes resulting from operations acquired or sold.

Changes in net working capital accounted for inflows of $71 million, $44 million and $142 million in 2015, 2014 and 2013, respectively, and were driven by the following:

- Accounts receivable - Changes in accounts receivable resulted in a $261 million inflow of cash in 2015 compared to $16 million of cash outflows in 2014 and $43 million of cash inflows in 2013. The larger use of cash during 2014 was due to increased sales compared to 2015 and 2013.
- Inventory - Changes in inventory resulted in cash inflows of $39 million in 2015 compared to cash outflows of $4 million in 2014 and cash inflows of $106 million in 2013. During 2013, there were decreased inventory levels, primarily within the Specialty Ingredients reportable segment, resulting from lower value guar-based product sold during the year.
- Trade and other payables - Changes in trade and other payables resulted in cash outflows of $229 million in 2015 compared to cash inflows of $64 million in 2014 and cash outflows of $7 million in 2013. During 2014, there were increased accruals for incentive compensation and severance related to the 2014 global restructuring which resulted in large cash outflows in 2015. Approximately $60 million of incentive compensation payments and $45 million of severance payments related to restructuring activities were made during 2015 compared to 2014 which had approximately $15 million of incentive compensation payments and $52 million of severance payments.

The remaining cash outflows during 2015, 2014, and 2013 of $303 million, $131 million and $139 million, respectively, were primarily due to income taxes paid, interest paid, and adjustments to certain accruals and long term assets and liabilities.

Operating cash flows for 2015 included income from continuing operations of $191 million, $255 million of net losses on pension and other postretirement plan remeasurements and noncash adjustments of $341 million for depreciation and amortization, and $18 million for debt issuance cost amortization. Operating cash flows for 2015 also included noncash adjustments of $25 million related to the impairment of the Venezuelan joint venture equity investment and certain IPR&D assets associated with the acquisition of ISP.

Operating cash flows for 2014 included income from continuing operations of $72 million, $438 million of net losses on pension and other postretirement plan remeasurements and noncash adjustments of $393 million for depreciation and amortization, which includes a $19 million impairment related to a foreign operation and $14 million for debt issuance cost amortization. Operating cash flows for 2014 also included impairments totaling $63 million related to the ASK joint venture equity investment and IPR&D assets.

Operating cash flows for 2013 included income from continuing operations of $553 million, a $417 million actuarial gain on pension and other postretirement plan remeasurement and noncash adjustments of $356 million for depreciation and amortization, and $65 million for debt issuance cost amortization. Operating cash flows for 2013 also included impairments totaling $41 million related to certain IPR&D assets associated with the acquisition of ISP.

Investing activities

The following discloses the cash flows associated with Ashland's investing activities for 2015, 2014 and 2013.

(In millions)	2015	2014	2013
Cash flows provided (used) by investing activities from continuing operations			
Additions to property, plant and equipment	$ (265)	$ (248)	$ (264)
Proceeds from disposal of property, plant and equipment	3	3	5
Purchase of operations - net of cash acquired	(13)	—	—
Proceeds (uses) from sale of operations or equity investments	161	92	(13)
Proceeds from sales of available-for-sale securities	315	—	—
Purchase of available-for-sale securities	(315)	—	—
Funds restricted for specific transactions	(320)	(15)	—
Reimbursements from restricted investments	6	—	—
Proceeds from the settlement of derivative instruments	18	—	—
Payments from the settlement of derivative instruments	(7)	—	—
Total cash flows used by investing activities from continuing operations	$ (417)	$ (168)	$ (272)

Cash used by investing activities was $417 million in 2015 compared to $168 million and $272 million for 2014 and 2013, respectively. The current period included capital expenditures of $265 million and proceeds of $105 million from the sale of the Elastomers division, approximately $30 million from the sale of industrial biocides assets and $24 million from the sale of Valvoline car care product assets. Funds restricted for specific transactions represent the receipt of the January 2015 asbestos insurance settlement funds of $335 million into a restrictive renewable annual trust, partially offset by the reclassification into cash and cash equivalents of $15 million of assets previously restricted in use for property transactions. The previous restriction of the $15 million for property transactions occurred in 2014 and is reflected as an investing outflow during 2014. From the restrictive renewable annual trust (derived from the asbestos proceeds received during 2015), Ashland received a $6 million reimbursement for certain 2015 asbestos disbursements. Additionally, the purchase of and proceeds from the sale of available-for-sale securities of $315 million relate to investment activity involving equity and corporate bond funds within the asbestos trust.

The significant cash investing activities for 2014 included cash outflows of $248 million for capital expenditures and restricted cash for property transactions of $15 million previously discussed. These outflows were partially offset by cash inflows related to the sale of the ASK equity investment of $87 million and $5 million related to tax receipt from a previously divested business. The significant cash investing activities for 2013 included cash outflows of $264 million for capital expenditures.

Financing activities

The following discloses the cash flows associated with Ashland's financing activities for 2015, 2014 and 2013, respectively.

(In millions)	2015	2014	2013
Cash flows provided (used) by financing activities from continuing operations			
Proceeds from issuance of long-term debt	$ 1,100	$ —	$ 2,320
Repayment of long-term debt	(623)	(11)	(2,613)
Premium on long-term debt repayment	(9)	—	—
Proceeds (repayment) from short-term debt	(3)	22	(36)
Repurchase of common stock	(397)	(954)	(150)
Debt issuance costs	(9)	—	(38)
Cash dividends paid	(98)	(103)	(88)
Excess tax benefits related to share-based payments	9	12	13
Total cash flows used by financing activities from continuing operations	$ (30)	$ (1,034)	$ (592)

Cash used by financing activities was $30 million for 2015, $1,034 million for 2014, and $592 million for 2013. Significant cash financing activities during 2015 primarily included the 2015 Senior Credit Agreement, the redemption of the 2016 senior notes, and the repurchase of common stock. As a result of the 2015 Senior Credit Agreement and redemption of the 2016 senior notes, Ashland received $1,100 million from the issuance of the term loan facility, repaid $600 million related to the 2016 senior

notes, paid early redemption premiums of $9 million and debt issuance costs of $9 million. In addition, Ashland repurchased $397 million of common stock under the $1.35 billion common stock repurchase program and paid cash dividends of $1.46 per share, for a total of $98 million.

Significant cash financing activities for 2014 included a $954 million cash outflow related to the repurchase of common stock under the $1.35 billion common stock repurchase program. Other significant cash financing activities for 2014 included cash outflows of $11 million in repayments of long-term debt and $103 million in cash dividends paid at $1.36 per share, as well as cash inflows of $22 million primarily related to draw on the revolver and $12 million for proceeds from the exercise of stock options and excess tax benefits related to share-based payments.

Significant cash financing activities for 2013 included the proceeds of $2.3 billion related to Ashland's issuance of the senior notes, offset by repayments of short term debt of $36 million, as well as $2.6 billion in repayments of long-term debt, primarily a result of Ashland's repayment of its term loan A and term loan B facilities. Other significant financing activities for 2013 included $150 million in common stock repurchased, cash dividends paid of $1.13 per share, that totaled $88 million, $38 million in cash paid for debt issuance costs, as well as cash inflows of $13 million for proceeds from the exercise of stock options and excess tax benefits related to share-based payments.

Cash provided by discontinued operations

The following discloses the cash flows associated with Ashland's discontinued operations for 2015, 2014 and 2013, respectively.

(In millions)	2015	2014	2013
Cash provided (used) by discontinued operations			
Operating cash flows	$ 245	$ 63	$ 80
Investing cash flows	24	1,608	(48)
Total cash flows provided by discontinued operations	$ 269	$ 1,671	$ 32

Cash provided by discontinued operations during 2015 included $398 million of cash received, before taxes, related to the January 2015 asbestos insurance settlement, and $48 million of delayed cash proceeds for a foreign entity from the sale of Water Technologies. These inflows were partially offset by $91 million in tax payments primarily from the Water Technologies sale and a $20 million payment for the working capital settlement related to the disposition of Water Technologies.

Cash provided by discontinued operations during 2014 included $1.6 billion of net proceeds from the sale of Water Technologies, net of working capital and other adjustments as defined in the definitive sale agreement as well as transaction costs. Excluding the $1.6 billion of proceeds, the remaining cash flows related to Water Technologies were $68 million in 2014. Cash provided by discontinued operations during 2013 includes Water Technologies activities of $125 million.

The remaining cash flows in each fiscal year principally related to other previously divested businesses and to payment of asbestos and certain environmental liabilities.

Free cash flow and other liquidity information

The following represents Ashland's calculation of free cash flow for the disclosed periods and reconciles free cash flow to cash flows provided by operating activities from continuing operations. Free cash flow does not reflect adjustments for certain non-discretionary cash flows such as mandatory debt repayments. See "Results of Operations - Consolidated Review - Use of non-GAAP measures" for additional information.

	September 30		
(In millions)	2015	2014	2013
Cash flows provided by operating activities from continuing operations	$ 89	$ 580	$ 653
Less:			
Additions to property, plant and equipment	(265)	(248)	(264)
Discretionary contribution to pension plans	500	—	—
Payment resulting from termination of interest rate swaps (a)	—	—	52
Free cash flows	$ 324	$ 332	$ 441

(a) Since payment was generated from financing activity, this amount has been included within this calculation.

At September 30, 2015, working capital (current assets minus current liabilities, excluding long-term debt due within one year) amounted to $1,855 million, compared to $1,883 million at the end of 2014. Ashland's working capital is affected by its use of the LIFO method of inventory valuation that valued inventories below their replacement costs by $34 million at September 30, 2015 and $31 million at September 30, 2014. Liquid assets (cash, cash equivalents and accounts receivable) amounted to 153% of current liabilities at September 30, 2015 and 154% at September 30, 2014.

The following summary reflects Ashland's cash, investment securities and unused borrowing capacity as of September 30, 2015, 2014 and 2013.

	September 30		
(In millions)	2015	2014	2013
Cash and cash equivalents	$ 1,257	$ 1,393	$ 346
Unused borrowing capacity			
Revolving credit facility	$ 1,013	$ 1,084	$ 1,119
Accounts receivable securitization facility	$ 10	$ —	$ 80

Total borrowing capacity remaining under the $1.2 billion senior unsecured revolving credit facility (the 2015 revolving credit facility) was $1,013 million, due to an outstanding balance of $110 million, as well as a reduction of $77 million for letters of credit outstanding at September 30, 2015. In total, Ashland's available liquidity position, which includes cash, the revolving credit facility and accounts receivable securitization facility, was $2,280 million at September 30, 2015 as compared to $2,477 million at September 30, 2014 and $1,545 million at September 30, 2013. For further information, see Note I within Notes to Consolidated Financial Statements.

Capital resources

Debt

The following summary reflects Ashland's debt as of September 30, 2015 and 2014.

	September 30	
(In millions)	2015	2014
Short-term debt	$ 326	$ 329
Long-term debt (including current portion and debt issuance cost discounts) (a)	3,403	2,920
Total debt	$ 3,729	$ 3,249

(a) Includes $28 million and $31 million of debt issuance cost discounts as of September 30, 2015 and 2014, respectively.

The current portion of long-term debt was $55 million at September 30, 2015 and $9 million at September 30, 2014. Debt as a percent of capital employed was 55% at September 30, 2015 and 48% at September 30, 2014. At September 30, 2015, Ashland's total debt had an outstanding principal balance of $3,907 million, discounts of $150 million, and debt issuance costs of $28 million. The scheduled aggregate maturities of debt for the next five fiscal years are as follows: $381 million in 2016, $69 million in 2017, $810 million in 2018, $143 million in 2019 and $715 million in 2020.

Debt activity during 2015

During June of 2015, Ashland completed certain refinancing transactions related to the $600 million 3.000% senior notes due in 2016 (2016 senior notes). Ashland commenced and completed a cash tender offer to purchase for cash any and all of its outstanding 2016 senior notes. At the close of the tender offer, $550 million aggregate principal amount of the 2016 senior notes was tendered by note holders, representing approximately 92% of the outstanding 2016 senior notes, which have been purchased by Ashland. Subsequently, Ashland redeemed the remaining balance of the 2016 senior notes of $50 million on July 23, 2015.

In connection with the tender offer and redemption, in June 2015, Ashland entered into a new Credit Agreement (the 2015 Senior Credit Agreement). The 2015 Senior Credit Agreement replaced the $1.2 billion senior unsecured revolving credit facility (the 2013 Senior Credit Facility), and was comprised of a new five-year senior unsecured revolving credit facility in an aggregate amount of $1.2 billion (the 2015 revolving credit facility), which includes a $250 million letter of credit sublimit and a $100 million swing line loan sublimit, and a five-year senior unsecured term loan facility in an aggregate principal amount of $1.1 billion (the

term loan facility). The 2015 Senior Credit Agreement is not guaranteed, is unsecured and can be prepaid at any time without premium or penalty.

At Ashland's option, borrowings under the 2015 revolving credit facility will bear interest at either LIBOR or an alternate base rate, in each case plus the applicable interest rate margin. The loans' interest rate will fluctuate between LIBOR plus 1.375% per annum and LIBOR plus 2.50% per annum (or between the alternate base rate plus 0.375% per annum and the alternate base rate plus 1.50% per annum), based upon Ashland's corporate credit ratings or the consolidated gross leverage ratio (as defined in the 2015 Senior Credit Agreement) (whichever yields a lower applicable interest rate margin) at such time. In addition, Ashland was required to pay fees of 0.25% per annum on the daily unused amount of the 2015 revolving credit facility through and including June 30, 2015, and thereafter the fee rate will fluctuate between 0.175% and 0.40% per annum, based upon Ashland's corporate credit ratings or the consolidated gross leverage ratio (whichever yields a lower fee rate).

During 2015, the potential funding for qualified receivables was reduced from $275 million to $250 million. Under the terms of the Transfer and Administration Agreement, CVG Capital III LLC, a wholly-owned "bankruptcy remote" special purpose subsidiary of the Originators (CVG) may, from time to time, obtain up to now $250 million (in the form of cash or letters of credit for the benefit of Ashland and its subsidiaries) from the Conduit Investors, the Uncommitted Investors and/or the Committed Investors through the sale of an undivided interest in such accounts receivable, related assets and collections. Additionally, during 2015, the termination of the commitments under the Transfer and Administration Agreement under the accounts receivable securitization was extended from August 28, 2015 to December 31, 2015. See Note I of the Notes to Consolidated Financial Statements for further information on this agreement.

At September 30, 2015 and 2014, the outstanding amount of accounts receivable transferred by Ashland to CVG was $381 million and $493 million, respectively. Ashland had drawn $190 million and $255 million, respectively, under the facility as of September 30, 2015 and 2014 in available funding from qualifying receivables. The weighted-average interest rate for this instrument was 1.8% for 2015 and 1.0% for 2014.

Debt activity during 2014

During 2014, the available funding for qualifying receivables under the accounts receivable securitization facility, entered into in 2012, was reduced from $350 million to $275 million due to the elimination of Water Technologies as a participant in the accounts receivable securitization. No other material terms of the agreement were amended. The Transfer and Administration Agreement had a term of three years, expiring in August 2015, but was extendable at the discretion of the Investors. See previous discussion on extension during 2015.

Debt covenant restrictions

The 2015 Senior Credit Agreement contains usual and customary representations, warranties and affirmative and negative covenants, including financial covenants for leverage and interest coverage ratios, limitations on liens, additional subsidiary indebtedness, restrictions on subsidiary distributions, investments, mergers, sale of assets and restricted payments and other customary limitations. As of September 30, 2015, Ashland is in compliance with all debt agreement covenant restrictions.

The 2015 Senior Credit Agreement defines the consolidated leverage ratio as the ratio of consolidated indebtedness minus cash and cash equivalents to consolidated EBITDA (Covenant Adjusted EBITDA) for any measurement period. In general, the 2015 Senior Credit Agreement defines Covenant Adjusted EBITDA as net income plus consolidated interest charges, taxes, depreciation and amortization expense, fees and expenses related to capital market transactions, restructuring and integration charges, noncash stock and equity compensation expense, and any other nonrecurring expenses or losses that do not represent a cash item in such period or any future period; less any noncash gains or other items increasing net income. The computation of Covenant Adjusted EBITDA differs from the calculation of EBITDA and Adjusted EBITDA, which have been reconciled previously on page M-7. In general, consolidated indebtedness includes debt plus all purchase money indebtedness, banker's acceptances and bank guaranties, deferred purchase price of property or services, attributable indebtedness and guarantees. The maximum consolidated leverage ratios permitted under the 2015 Senior Credit Agreement are as follows: 3.75 from June 30, 2015 through December 31, 2016 and 3.5 from March 31, 2017 and each fiscal quarter thereafter.

The 2015 Senior Credit Agreement defines the consolidated interest coverage ratio as the ratio of Covenant Adjusted EBITDA to consolidated interest charges for any measurement period. The minimum required consolidated interest coverage ratio under the 2015 Senior Credit Agreement during its entire duration is 3.0.

At September 30, 2015, Ashland's calculation of the consolidated leverage ratio was 2.6 compared to the maximum consolidated leverage ratio permitted under the 2015 Senior Credit Agreement of 3.75. At September 30, 2015, Ashland's calculation of the consolidated interest coverage ratio was 6.4 compared to the minimum required ratio of 3.0. Any change in Covenant Adjusted EBITDA of $100 million would have an approximate 0.3x effect on the consolidated leverage ratio and a 0.7x effect on the consolidated interest coverage ratio. Any change in consolidated indebtedness of $100 million would affect the consolidated leverage ratio by approximately 0.1x.

Cash projection

Ashland projects that cash flow from operations and other available financial resources such as cash on hand and revolving credit should be sufficient to meet investing and financing requirements to enable Ashland to comply with the covenants and other terms of its financing obligations. These projections are based on various assumptions that include, but are not limited to: operational results, working capital cash generation, capital expenditures, pension funding requirements and tax payment and receipts.

Based on Ashland's current debt structure, future annual interest expense is expected to be approximately $170 million based on applicable fixed and floating interest rates, assuming interest rates remain stable.

Stockholders' equity

Stockholders' equity decreased $546 million since September 30, 2014 to $3,037 million at September 30, 2015. This decrease was primarily due to $397 million related to share repurchase programs, deferred translation losses of $369 million, cash dividends of $98 million, adjustments to pension and other postretirement obligations of $18 million, and $11 million for an unrealized loss on available-for-sale securities. These decreases were partially offset by net income during the period of $309 million and $38 million in common shares issued under stock incentive and other plans.

Stock repurchase programs

During the past three fiscal years, Ashland's Board of Directors has authorized multiple share repurchase programs which are summarized below.

During 2015, Ashland's Board of Directors approved a new $1 billion share repurchase authorization that will expire on December 31, 2017. This authorization allows for common shares to be repurchased in open market transactions, privately negotiated transactions or pursuant to one or more accelerated stock repurchase programs or Rule 10b5-1 plans. See the "Key Developments" section of Management's Discussion and Analysis herein for information on 2016 stock repurchase activity.

During 2014, the Board of Directors of Ashland authorized a $1.35 billion common stock repurchase program (the 2014 stock repurchase program). Under the program, Ashland's common shares were repurchased pursuant to accelerated stock repurchase agreements, a Rule 10b5-1 plan, and a prepaid variable share repurchase agreement. This repurchase program was completed during 2015. The 2014 stock repurchase program authorization replaced Ashland's previous $600 million share repurchase authorization (the 2013 stock repurchase program), approved in May 2013, which had $450 million remaining when it was terminated.

The following stock repurchase agreements were entered into as part of the $1.35 billion common stock repurchase program.

Accelerated stock repurchase agreements

During 2014, Ashland announced that it has entered into accelerated share repurchase agreements (2014 ASR Agreements) with Deutsche Bank AG, London Branch (Deutsche Bank), and JPMorgan Chase Bank, N.A. (JPMorgan) to repurchase an aggregate of $750 million of Ashland's common stock. Under the 2014 ASR Agreements, Ashland paid an initial purchase price of $750 million, split evenly between the financial institutions. As of September 30, 2014, Ashland received an initial delivery of approximately 5.9 million shares of common stock under the 2014 ASR Agreements. The 2014 ASR Agreements had a variable maturity, at the financial institutions option, with a maximum pricing period termination date of June 30, 2015. During 2015, the 2014 ASR Agreements terminated pursuant to their terms and the pricing period was closed. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $116.33 per share. Based on this settlement price, the final number of shares repurchased by Ashland that were delivered by the financial institutions under the 2014 ASR Agreements was 6.4 million shares. Ashland received the additional 0.5 million shares from the financial institutions during 2015 to settle the difference between the initial share delivery and the total number of shares repurchased.

During 2015, Ashland announced and completed accelerated share repurchase agreements (2015 ASR Agreements) with Deutsche Bank and JPMorgan to repurchase an aggregate of $270 million of Ashland's common stock. Under the 2015 ASR Agreements, Ashland paid an initial purchase price of $270 million, split evenly between the financial institutions and received an initial delivery of approximately 1.9 million shares of common stock. The 2015 ASR Agreements had a variable maturity, at the financial institutions option, with a maximum pricing period termination date of July 31, 2015. During 2015, Deutsche Bank and JPMorgan exercised their early termination option under the 2015 ASR Agreements and the pricing period was closed. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $125.22 per share. Based on this settlement price, the final number of shares repurchased by Ashland that were delivered by the financial institutions under the 2015 ASR Agreements was 2.2 million shares. Ashland received the additional 0.3 million shares from the financial institutions during 2015 to settle the difference between the initial share delivery and the total number of shares repurchased.

Additional stock repurchase agreements

Ashland entered into and completed a $125 million prepaid variable share repurchase agreement during 2014. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $105.22 per share. Ashland received 0.8 million shares and $45 million in cash for the unused portion of the $125 million prepayment, for a net cash outlay of $80 million.

During 2014, Ashland announced that it had entered into an agreement with each of Deutsche Bank Securities Inc. and JPMorgan to repurchase an aggregate of $250 million of Ashland's common stock. Under the terms of the agreement, the financial institutions purchased a pre-determined number of shares on various trading days dependent upon Ashland's prevailing stock price on that date. During 2014, Ashland received 1.2 million shares of common stock for a total cost of $124 million. During 2015, Ashland completed these agreements, receiving an additional 1.2 million shares of common stock for a total cost of $127 million. The settlement price, which represents the average amount spent after commissions over the common shares repurchased throughout the program, was $104.51 per share. In total, Ashland paid $250 million and received 2.4 million shares of common stock under the agreements.

2013 stock repurchase program agreement

As part of the $600 million common stock repurchase program, Ashland announced and completed an accelerated share repurchase agreement (2013 ASR Agreement) with Citibank, N.A. (Citibank) during 2013. Under the 2013 ASR Agreement, Ashland paid an initial purchase price of $150 million to Citibank and received an initial delivery of approximately 1.3 million shares of its common stock. The 2013 ASR Agreement had a variable maturity, at Citibank's option, with a maximum pricing period termination date of August 21, 2013. In June 2013, Citibank exercised its early termination option under the 2013 ASR Agreement and the pricing period was closed. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $86.32 per share. Based on this settlement price, the final number of shares repurchased by Ashland that were to be delivered by Citibank under the 2013 ASR Agreement was 1.7 million shares. Ashland received the additional 0.4 million shares from Citibank in 2013 to settle the difference between the initial share delivery and the total number of shares repurchased.

Stockholder dividends

In May 2015, the Board of Directors of Ashland announced a quarterly cash dividend increase to 39 cents per share, $1.56 per share on an annual basis, to eligible shareholders of record. This amount was paid for quarterly dividends in June and September 2015 and was an increase from the quarterly cash dividend of 34 cents per share paid during the first and second quarters of fiscal 2015.

In May 2013, the Board of Directors of Ashland announced a quarterly cash dividend increase to 34 cents per share, $1.36 per share on an annual basis, to eligible shareholders of record. This amount was paid for quarterly dividends in fiscal 2014, as well as, June and September 2013 and was an increase from the quarterly cash dividend of 22.5 cents per share paid during the first and second quarters of fiscal 2013.

Capital expenditures

Ashland is currently forecasting approximately $320 million to $340 million of capital expenditures for 2016, funded primarily from operating cash flows. Capital expenditures were $265 million for 2015 and averaged $259 million during the last three years. A summary of capital expenditures by reportable segment during 2015, 2014 and 2013 follow.

(In millions)	2015	2014	2013
Specialty Ingredients	$ 171	$ 159	$ 144
Performance Materials	33	38	43
Valvoline	45	36	41
Unallocated and other	16	15	36
Total capital expenditures	$ 265	$ 248	$ 264

A summary of the capital employed in Ashland's current operations, which is calculated by adding equity to capital investment, as of the end of the last three years follows.

(In millions)	2015	2014	2013
Capital employed (a)			
Specialty Ingredients	$ 5,043	$ 5,413	$ 5,646
Performance Materials (b)	870	1,121	1,280
Valvoline	653	746	702

(a) Excludes the assets and liabilities classified within unallocated and other which primarily includes debt and other long-term liabilities such as asbestos and pension. The net liability in unallocated and other was $3,529 million, $3,697 million and $3,075 million as of September 30, 2015, 2014 and 2013, respectively.
(b) Decline primarily due to sale of Elastomers during 2015.

Contractual obligations and other commitments

The following table aggregates Ashland's obligations and commitments to make future payments under existing contracts at September 30, 2015. Contractual obligations for which the ultimate settlement of quantities or prices are not fixed and determinable have been excluded.

(In millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations					
Raw material and service contract purchase obligations (a)	$ 651	$ 176	$ 244	$ 119	$ 112
Employee benefit obligations (b)	334	49	67	65	153
Operating lease obligations (c)	190	40	55	34	61
Debt (d)	3,907	381	879	858	1,789
Interest payments (e)	1,551	154	297	238	862
Unrecognized tax benefits (f)	144	—	—	—	144
Total contractual obligations	$ 6,777	$ 800	$ 1,542	$ 1,314	$ 3,121
Other commitments					
Letters of credit (g)	$ 77	$ 77	$ —	$ —	$ —

(a) Includes raw material and service contracts where minimal committed quantities and prices are fixed.
(b) Includes estimated funding of Ashland's qualified U.S. and non-U.S. pension plans for 2016, as well as projected benefit payments through 2025 under Ashland's unfunded pension and other postretirement benefit plans. Excludes the benefit payments from the pension plan trust funds. See Note M of Notes to Consolidated Financial Statements for additional information.
(c) Includes leases for office buildings, retail outlets, transportation equipment, warehouses and storage facilities and other equipment. For further information, see Note K of Notes to Consolidated Financial Statements.
(d) Capitalized lease obligations are not significant and are included within this caption. For further information, see Note I of Notes to Consolidated Financial Statements.
(e) Includes interest expense on both variable and fixed rate debt assuming no prepayments. Variable interest rates have been assumed to remain constant through the end of the term at rates that existed as of September 30, 2015.
(f) Due to uncertainties in the timing of the effective settlement of tax positions with respect to taxing authorities, Ashland is unable to determine the timing of payments related to noncurrent unrecognized tax benefits, including interest and penalties. Therefore, these amounts were included in the "More than 5 years" column.
(g) Ashland issues various types of letters of credit as part of its normal course of business. For further information, see Note I of Notes to Consolidated Financial Statements.

OFF-BALANCE SHEET ARRANGEMENTS

As part of its normal course of business, Ashland is a party to various financial guarantees and other commitments. These arrangements involve elements of performance and credit risk that are not included in the Consolidated Balance Sheets. The possibility that Ashland would have to make actual cash expenditures in connection with these obligations is largely dependent on the performance of the guaranteed party, or the occurrence of future events that Ashland is unable to predict. Ashland has reserved the approximate fair value of these guarantees in accordance with U.S. GAAP.

NEW ACCOUNTING PRONOUNCEMENTS

For a discussion and analysis of recently issued accounting pronouncements and its impact on Ashland, see Note A of Notes to Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES

The preparation of Ashland's Consolidated Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, sales and expenses, and the disclosures of contingent assets and liabilities. Significant items that are subject to such estimates and assumptions include, but are not limited to, long-lived assets (including goodwill and other intangible assets), employee benefit obligations, income taxes, liabilities and receivables associated with asbestos litigation and environmental remediation. Although management bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, actual results could differ significantly from the estimates under different assumptions or conditions. Management has reviewed the estimates affecting these items with the Audit Committee of Ashland's Board of Directors.

Long-lived assets

Tangible assets

The cost of property, plant and equipment is depreciated by the straight-line method over the estimated useful lives of the assets. Buildings are depreciated principally over 25 to 35 years and machinery and equipment principally over 2 to 25 years. Ashland reviews property, plant and equipment asset groups for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. Ashland monitors these changes and events on at least a quarterly basis. Examples of events or changes in circumstances could include, but are not limited to, a prolonged economic downturn, current period operating or cash flow losses combined with a history of losses or a forecast of continuing losses associated with the use of an asset group, or a current expectation that an asset group will be sold or disposed of before the end of its previously estimated useful life. Recoverability is based upon projections of anticipated future undiscounted cash flows associated with the use and eventual disposal of the property, plant and equipment asset groups, as well as specific appraisals in certain instances. Reviews occur at the lowest level for which identifiable cash flows are largely independent of cash flows associated with other property, plant and equipment asset groups. If the future undiscounted cash flows result in a value that is less than the carrying value, then the long-lived asset is considered impaired and a loss is recognized based on the amount by which the carrying amount exceeds the estimated fair value. Various factors that Ashland uses in determining the impact of these assessments include the expected useful lives of long-lived assets and the ability to realize any undiscounted cash flows in excess of the carrying amounts of such asset groups, and are affected primarily by changes in the expected use of the assets, changes in technology or development of alternative assets, changes in economic conditions, changes in operating performance and changes in expected future cash flows. Because judgment is involved in determining the fair value of property, plant and equipment asset groups, there is risk that the carrying value of these assets may require adjustment in future periods.

Total depreciation expense on property, plant and equipment for 2015, 2014 and 2013 was $263 million, $304 million and $268 million, respectively. Depreciation expense for 2015, 2014 and 2013 included $6 million, $36 million and $2 million, respectively, in accelerated depreciation and asset impairments. Capitalized interest was $2 million for 2015 and $1 million for each of 2014 and 2013.

Finite-lived intangible assets

Finite-lived intangible assets principally consist of certain trademarks and trade names, intellectual property, and customer relationships. These intangible assets are amortized on a straight-line basis over their estimated useful lives. The cost of trademarks and trade names is amortized principally over 4 to 25 years, intellectual property over 5 to 20 years and customer relationships over 3 to 24 years. Ashland reviews finite-lived intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. Ashland monitors these changes and events on at least a quarterly basis.

Amortization expense recognized on finite-lived intangible assets was $78 million for 2015, $89 million for 2014 and $88 million for 2013, and is primarily included in the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income.

Goodwill

Ashland reviews goodwill and indefinite-lived intangible assets for impairment annually or when events and circumstances indicate an impairment may have occurred. This annual assessment is performed as of July 1 and consists of Ashland determining each reporting unit's current fair value compared to its current carrying value. Subsequent to the business realignment during 2014 and the December 1, 2014 sale of the Elastomers division, which was previously a reporting unit, Ashland determined that

its reporting units for the allocation of goodwill include the Specialty Ingredients and Valvoline reportable segments, and the Composites and Intermediates/Solvents reporting units within the Performance Materials reportable segment.

Prior to the business realignment in 2014, the reporting units consisted of the Specialty Ingredients and Valvoline reportable segments, and the Composites and Adhesives reporting unit and the Elastomers reporting unit within the Performance Materials reportable segment. In accordance with U.S. GAAP, as a result of the business realignment in 2014, goodwill was reallocated using a relative fair value approach and Ashland performed an assessment to determine if an impairment existed. Upon completion of this assessment, Ashland concluded that no impairment existed.

Goodwill associated with the reporting units as of September 30, 2015 was $2,004 million for Specialty Ingredients, $169 million for Valvoline, $142 million for Composites and $171 million for Intermediates/Solvents.

Ashland makes various estimates and assumptions in determining the estimated fair values of its reporting units through the use of a combination of discounted cash flow models and valuations based on earnings multiples for guideline public companies in each reporting unit's industry peer group. Discounted cash flow models are highly reliant on various assumptions. Significant assumptions Ashland utilized in these models for the current year included: projected business results and future industry direction, long-term growth factors and weighted-average cost of capital. Ashland uses assumptions that it deems to be reasonable estimates of likely future events and compares the total fair values of each reporting unit to Ashland's market capitalization, and implied control premium, to determine if the fair values are reasonable compared to external market indicators. Subsequent changes in these key assumptions could affect the results of future goodwill impairment reviews. The assumptions utilized in the current year models are generally consistent with the prior year models.

In conjunction with the July 1, 2015 annual assessment of goodwill, Ashland's valuation techniques did not indicate any impairment. The base models of future financial performance projections utilized in the goodwill impairment assessment reflect conservative assumptions on future operating performance as approved by Management and the Board of Directors. The results of the impairment analysis for each reporting unit are consistent with the prior year. Each reporting unit's fair value exceeded its carrying values, with the Intermediates/Solvents reporting unit, having the closest calculated fair value to its carrying value of approximately 10%. Based on the sensitivity analysis performed on two key assumptions in the discounted cash flow model of the Intermediates/Solvents reporting unit, a negative 1% change in the long-term growth factor or the weighted-average cost of capital assumption would have resulted in a fair value slightly above the current carrying value. The operating results for the Intermediates/Solvents reporting unit improved from the prior year goodwill impairment test, reflecting increased financial profitability. Despite improved operating results, this reporting unit continues to be at some risk for potential impairment in future periods given the volatility in industry economics. Ashland will continue to monitor all reporting units during fiscal 2016.

Ashland compared and assessed the total fair values of the reporting units to Ashland's market capitalization at the annual assessment date, including the implied control premium, to determine if the fair values are reasonable compared to external market indicators. Ashland's market value as of the annual impairment testing date for 2015 exceeded the calculated fair value for each reporting unit summed together by approximately 15%, which Ashland considers to be indicative of the conservatism built into its fair value models. Because the fair value results for each reporting unit did not indicate a potential impairment existed, Ashland did not recognize any goodwill impairment during 2015, 2014 and 2013. Subsequent to this annual impairment test, no indications of an impairment were identified.

Other indefinite-lived intangible assets

Other indefinite-lived intangible assets include in-process research and development (IPR&D) and certain trademarks and trade names. These assets had a carrying value of $311 million as of September 30, 2015. Ashland reviews these intangible assets for possible impairment annually or whenever events or changes in circumstances indicate that carrying amounts may not be recoverable. Ashland tests these assets using a "relief-from-royalty" valuation method compared to the carrying value, except for IPR&D assets, which are described within its section. Significant assumptions inherent in the valuation methodologies for these intangibles include, but are not limited to, such estimates as projected business results, growth rates, weighted-average cost of capital, and royalty rates. The assumptions utilized in the current year models are generally consistent with the prior year models. In conjunction with the July 1 annual assessment of indefinite-lived intangible assets, Ashland's models did not indicate any impairment, as each indefinite-lived intangible asset's fair value exceeded their carrying values.

Ashland's assessment of an impairment charge on any of these assets classified currently as having indefinite lives, including goodwill, could change in future periods if any or all of the following events were to occur with respect to a particular reporting unit: a significant change in projected business results, a divestiture decision, increase in Ashland's weighted-average cost of capital rates, decrease in growth rates or other assumptions, economic deterioration that is more severe or of a longer duration than anticipated, or another significant economic event. For further information, see Note H of Notes to Consolidated Financial Statements.

IPR&D

Ashland identified in-process research and development (IPR&D) projects within the acquired ISP business during 2011 that, as of the date of acquisition, had not been established in the marketplace. These projects consist of various enhancements of existing products or new potential applications for products. Ashland used various valuation models based on discounted probability weighted future cash flows on a project-by-project basis in identifying projects as distinct assets. Identified IPR&D acquired in a business combination is capitalized and tested for impairment annually and when events and circumstances indicate an impairment may have occurred. Subsequent to the acquisition of ISP, several projects were abandoned or impaired as a result of interim and annual impairment tests. The remaining projects were assessed throughout 2015, 2014 and 2013, resulting in decreases of $11 million in 2015, $13 million in 2014 and $41 million in 2013 for projects abandoned or impaired during each year. Ashland has started amortizing remaining IPR&D assets during fiscal 2016 since the technology was commercialized during this period. For further information on IPR&D assets, see Note H of Notes to Consolidated Financial Statements.

Employee benefit obligations

Pension plans

Ashland and its subsidiaries sponsor contributory and noncontributory qualified defined benefit pension plans that cover certain employees in the United States and in a number of other countries. In addition, Ashland has non-qualified unfunded pension plans which provide supplemental defined benefits to those employees whose benefits under the qualified pension plans are limited by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. Ashland funds the costs of the non-qualified plans as the benefits are paid. Pension obligations for applicable employees of non-U.S. consolidated subsidiaries are provided for in accordance with local practices and regulations of the respective countries. For further information, see Note M of Notes to Consolidated Financial Statements.

Other postretirement benefit plans

Ashland and its subsidiaries sponsor health care and life insurance plans for eligible employees in the U.S. and Canada who retire or are disabled. Ashland's retiree life insurance plans are noncontributory, while Ashland shares the costs of providing health care coverage with its retired employees through premiums, deductibles and coinsurance provisions. Ashland funds its share of the costs of the postretirement benefit plans as the benefits are paid. For further information, see Note M of Notes to Consolidated Financial Statements.

Pension and other postretirement benefits costs methodology

Ashland recognizes the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and other postretirement benefits expense are recorded ratably on a quarterly basis. Pension and other postretirement benefits adjustments charged directly to cost of sales that are applicable to inactive participants are excluded from inventoriable costs. The service cost component of pension and other postretirement benefits costs is allocated to each reportable segment on a ratable basis; while the remaining components of pension and other postretirement benefits costs are recorded to Unallocated and other.

The following table discloses the components of the gain or loss on pension and other postretirement plan remeasurements for each of the last three years.

(In millions)	2015	2014	2013
Loss (gain) on pension and other postretirement plan remeasurement:			
Change in discount rate and other actuarial assumptions (a)	$ 13	$ 369	$ (575)
Change in mortality table (a)	47	149	—
Actual return on plan assets (a)	(15)	(309)	(161)
Expected return on plan assets (a)	216	237	238
Total actuarial loss (gain) on pension and other postretirement plan remeasurement	261	446	(498)
Curtailment, settlement and other loss	(11)	11	—
Total loss (gain) on pension and other postretirement plan remeasurement	250	457	(498)
Less: Actuarial loss (gain) recognized in discontinued operations	2	44	(81)
Less: Curtailment, settlement and other gain in discontinued operations	(7)	(25)	—
Total loss (gain) on pension and other postretirement plan remeasurement from continuing operations	$ 255	$ 438	$ (417)

(a) For additional information on key assumptions and actual plan asset performance in each year, see the "Actuarial assumptions" discussion within this section.

Actuarial assumptions

Ashland's pension and other postretirement obligations and annual expense calculations are based on a number of key assumptions including the discount rate at which obligations can be effectively settled, the anticipated rate of compensation increase, the expected long-term rate of return on plan assets and certain employee-related factors, such as turnover, retirement age and mortality. Because Ashland's retiree health care plans contain various caps that limit Ashland's contributions and because medical inflation is expected to continue at a rate in excess of these caps, the health care cost trend rate has no significant impact on Ashland's postretirement health care benefit costs.

Ashland developed the discount rate used to determine the present value of its obligations under the U.S. pension and postretirement health and life plans by matching the stream of benefit payments from the plans to spot rates determined from an actuarial-developed yield curve, the above mean yield curve, based on high-quality corporate bonds. Ashland uses this approach to reflect the specific cash flows of these plans when determining the discount rate. Non-U.S. pension plans followed a similar process based on financial markets in those countries where Ashland provides a defined benefit pension plan.

Ashland's expense, excluding actuarial gains and losses, for both U.S. and non-U.S. pension plans is determined using the weighted-average discount rate as of the beginning of the fiscal year, which were 4.18%, 4.68%, and 3.70% for the years ended September 30, 2015, 2014, and 2013, respectively. The weighted-average discount rates used for the postretirement health and life plans were 3.85%, 4.28%, and 3.23% for the years ended September 30, 2015, 2014, and 2013, respectively. The actuarial gains and losses recognized within the Statements of Consolidated Comprehensive Income are calculated using updated actuarial assumptions (including discount rates) as of the measurement date, which for Ashland is the end of the fiscal year, unless a plan qualifies for a remeasurement during the year. The weighted-average discount rate at the end of fiscal 2015 was 4.21% for the pension plans and 3.93% for the postretirement health and life plans.

The weighted-average rate of compensation increase assumptions were 3.18% for 2015, 3.59% for 2014 and 3.66% for 2013. The compensation increase assumptions for the U.S. plans were 3.20% for 2015, and 3.75% for 2014 and 2013. The rate of the compensation increase assumption for the U.S. plans will decrease to 3.00% in determining Ashland's pension costs for 2016.

During 2014, Ashland elected to update the mortality table assumption used to develop the U.S. pension and other postretirement health and life plans obligations. The prior and updated mortality table were both actuarially determined assumptions that represented the best available estimate at the end of the fiscal year. During 2015, Ashland updated the mortality assumption based on information issued by the Society of Actuaries in October 2015 for the U.S. pension and other postretirement health and life plans. Ashland believes the updated mortality table assumption provides a more accurate assessment of current mortality trends and is a reasonable estimate of future mortality projections.

The weighted-average long-term expected rate of return on assets was assumed to be 7.27% for 2015, 7.67% for 2014 and 7.26% for 2013. The long-term expected rate of return on assets for the U.S. plans was assumed to be 7.65% for 2015 and 8.00% for 2014 and 2013. For 2015, the pension plan assets generated an actual weighted-average return of 1.52%, compared to 10.62% in 2014 and 5.15% in 2013. For 2015, the U.S. pension plan assets generated an actual return of 0.44%, compared to 10.33% in 2014 and 5.24% in 2013. The long-term expected rate of return on assets for the U.S. plans will be 7.10% for 2016. However, the expected return on plan assets is designed to be a long-term assumption, and actual returns will be subject to considerable year-

to-year variances. Ashland estimates total fiscal 2016 pension income for U.S. and non-U.S. pension plans to be approximately $40 million, which excludes the impact of actuarial gains or losses.

The following table discloses the estimated increases in pension and postretirement expense that would have resulted from a one percentage point change in each of the assumptions for each of the last three years.

(In millions)	2015	2014	2013
Increase in pension costs from			
Decrease in the discount rate	$ 490	$ 591	$ 557
Increase in the salary adjustment rate	33	32	44
Decrease in expected return on plan assets	30	31	33
Increase in other postretirement costs from			
Decrease in the discount rate	20	20	20

During 2013, Ashland elected to use the above mean yield curve for its U.S. pension and other postretirement health and life plans, a change from the yield curve used in prior years. The above mean yield curve is constructed in the same manner as the prior yield curve, however, it uses only bonds in the population that had above average yields for their maturity. The discount rates determined as of September 30, 2013 ranged from 4.37% - 4.93% for the U.S. pension plans and 3.89% - 4.75% for the postretirement health and life plans. Under the prior yield curve, the September 30, 2013 discount rates would have ranged from 4.04% - 4.60% for the U.S. pension plans and 3.57% - 4.43% for the postretirement health and life plans. The use of the above mean yield curve resulted in Ashland recognizing an actuarial gain in 2013 that was approximately $146 million greater than the actuarial gain which would have been recognized using the prior yield curve, or 29% of the 2013 actuarial gain. Of this impact, $140 million related to U.S. pension plans and $6 million relates to U.S. postretirement plans.

U.S. pension legislation and future funding requirements

Ashland's U.S. qualified pension plans funding requirements through fiscal 2017 are calculated in accordance with the regulations set forth in the Moving Ahead for Progress in the 21st Century Act (MAP-21), which provides temporary relief for employers who sponsor defined benefit pension plans related to funding contributions under the Employee Retirement Income Security Act of 1974. Specifically, MAP-21 allows for the use of a 25-year average interest rate within an upper and lower range for purposes of determining minimum funding obligations instead of an average interest rate for the two most recent years, as was previously required.

During 2015, as a result of the $500 million discretionary contribution, Ashland's funding requirements to U.S. qualified pension plans have been eliminated for fiscal year 2016. Ashland expects to contribute approximately $15 million to its non-qualified U.S. pension plans and $15 million to its non-U.S. pension plans during 2016.

Income taxes

Ashland is subject to income taxes in the United States and numerous foreign jurisdictions. Significant judgment in the forecasting of taxable income using historical and projected future operating results is required in determining Ashland's provision for income taxes and the related assets and liabilities. The provision for income taxes includes income taxes paid, currently payable or receivable, and deferred taxes. Under U.S. GAAP, deferred tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities, and are measured using enacted tax rates and laws that are expected to be in effect when the differences reverse. Deferred tax assets are also recognized for the estimated future effects of tax loss carryforwards. The effect on deferred taxes of changes in tax rates is recognized in the period in which the enactment date occurs. Valuation allowances are established when necessary on a jurisdictional basis to reduce deferred tax assets to the amounts expected to be realized. Deferred taxes are not provided on the unremitted earnings of subsidiaries outside of the United States when it is expected that these earnings are indefinitely reinvested. In the event that the actual outcome of future tax consequences differs from Ashland's estimates and assumptions due to changes or future events such as tax legislation, geographic mix of earnings, completion of tax audits or earnings repatriation plans, the resulting change to the provision for income taxes could have a material effect on the Statement of Consolidated Comprehensive Income and Consolidated Balance Sheet.

The recoverability of deferred tax assets and the recognition and measurement of uncertain tax positions are subject to various assumptions and judgment by Ashland. If actual results differ from the estimates made by Ashland in establishing or maintaining valuation allowances against deferred tax assets, the resulting change in the valuation allowance would generally impact earnings or other comprehensive income depending on the nature of the respective deferred tax asset. Additionally, the positions taken with regard to tax contingencies may be subject to audit and review by tax authorities, which may result in future taxes, interest and penalties. Positive and negative evidence is considered in determining the need for a valuation allowance against deferred

tax assets, which includes such evidence as historical earnings, projected future earnings, tax planning strategies and expected timing of reversal of existing temporary differences.

In determining the recoverability of deferred tax assets Ashland gives consideration to all available positive and negative evidence including reversals of deferred tax liabilities (other than those with an indefinite reversal period), projected future taxable income, tax planning strategies and recent financial operations. Ashland attaches the most weight to historical earnings due to their verifiable nature. In evaluating the objective evidence that historical results provide, we consider three years of cumulative income or loss. In addition, Ashland has reflected increases and decreases in our valuation allowance based on the overall weight of positive versus negative evidence on a jurisdiction by jurisdiction basis. During 2015, Ashland reversed valuation allowances of $29 million primarily related to state deferred tax assets.

Asbestos litigation

Ashland and Hercules, a wholly-owned subsidiary of Ashland that was acquired in 2009, have liabilities from claims alleging personal injury caused by exposure to asbestos. To assist in developing and annually updating independent reserve estimates for future asbestos claims and related costs given various assumptions, Ashland retained Hamilton, Rabinovitz & Associates, Inc. (HR&A). The methodology used by HR&A to project future asbestos costs is based largely on recent experience, including claim-filing and settlement rates, disease mix, enacted legislation, open claims and litigation defense. The claim experience of Ashland and Hercules are separately compared to the results of previously conducted third party epidemiological studies estimating the number of people likely to develop asbestos-related diseases. Those studies were undertaken in connection with national analyses of the population expected to have been exposed to asbestos. Using that information, HR&A estimates a range of the number of future claims that may be filed, as well as the related costs that may be incurred in resolving those claims. Changes in asbestos-related liabilities and receivables are recorded on an after-tax basis within the discontinued operations caption in the Statements of Consolidated Comprehensive Income. See Note N of Notes to Consolidated Financial Statements for additional information.

Ashland asbestos-related litigation

The claims alleging personal injury caused by exposure to asbestos asserted against Ashland result primarily from indemnification obligations undertaken in 1990 in connection with the sale of Riley Stoker Corporation (Riley), a former subsidiary. The amount and timing of settlements and number of open claims can fluctuate significantly from period to period.

Ashland asbestos-related liability

From the range of estimates, Ashland records the amount it believes to be the best estimate of future payments for litigation defense and claim settlement costs, which generally approximates the mid-point of the estimated range of exposure from model results. Ashland reviews this estimate and related assumptions quarterly and annually updates the results of a non-inflated, non-discounted approximate 50-year model developed with the assistance of HR&A.

During the most recent update, completed during 2015, it was determined that the liability for Ashland asbestos claims did not need to be adjusted. Total reserves for asbestos claims were $409 million at September 30, 2015 compared to $438 million at September 30, 2014.

Ashland asbestos-related receivables

Ashland has insurance coverage for certain litigation defense and claim settlement costs incurred in connection with its asbestos claims, and coverage-in-place agreements exist with the insurance companies that provide substantially all of the coverage that will be accessed.

For the Ashland asbestos-related obligations, Ashland has estimated the value of probable insurance recoveries associated with its asbestos reserve based on management's interpretations and estimates surrounding the available or applicable insurance coverage, including an assumption that all solvent insurance carriers remain solvent. Substantially all of the estimated receivables from insurance companies are expected to be due from domestic insurers. Approximately 45% of the receivable is from insurance companies rated by A.M. Best, all of which have a credit rating of BBB+ or higher as of September 30, 2015.

In October 2012, Ashland and Hercules initiated various arbitration proceedings against Underwriters at Lloyd's, certain London companies and/or Chartis (AIG) member companies seeking to enforce these insurers' contractual obligations to provide indemnity for asbestos liabilities and defense costs under existing coverage-in-place agreements. In addition, Ashland and Hercules initiated a lawsuit in Kentucky state court against certain Berkshire Hathaway entities (National Indemnity Company and Resolute Management, Inc.) on grounds that these Berkshire Hathaway entities had wrongfully interfered with Underwriters' and Chartis' performance of their respective contractual obligations to provide asbestos coverage by directing the insurers to reduce and delay certain claim payments.

On January 13, 2015, Ashland and Hercules entered into a comprehensive settlement agreement related to certain insurance coverage for asbestos bodily injury claims with Underwriters at Lloyd's, certain London companies and Chartis (AIG) member companies, along with National Indemnity Company and Resolute Management, Inc., under which Ashland and Hercules received

a total of $398 million. In exchange, all claims were released against these entities for past, present and future coverage obligations arising out of the asbestos coverage-in-place agreements that were the subject of the pending arbitration proceedings. In addition, as part of this settlement, Ashland and Hercules released all claims against National Indemnity Company and Resolute Management, Inc. in the Kentucky state court action. As a result, the arbitration proceedings and the Kentucky state court action have been terminated.

As a result of this settlement, Ashland recorded an after-tax gain of $120 million within the discontinued operations caption of the Statements of Consolidated Comprehensive Income during 2015. The Ashland insurance receivable balance was also reduced as a result of this settlement by $227 million within the Consolidated Balance Sheets.

In addition, Ashland placed $335 million of the settlement funds received into a renewable annual trust restricted for the purpose of paying for ongoing and future litigation defense and claim settlement costs incurred in conjunction with asbestos claims.

At September 30, 2015, Ashland's receivable for recoveries of litigation defense and claim settlement costs from insurers amounted to $150 million (excluding the Hercules receivable for asbestos claims), of which $12 million relates to costs previously paid. Receivables from insurers amounted to $402 million at September 30, 2014. During 2015, the annual update of the model used for purposes of valuing the asbestos reserve and its impact on valuation of future recoveries from insurers, was completed. This model update resulted in a $3 million decrease in the receivable for probable insurance recoveries.

Hercules asbestos-related litigation

Hercules has liabilities from claims alleging personal injury caused by exposure to asbestos. Such claims typically arise from alleged exposure to asbestos fibers from resin encapsulated pipe and tank products which were sold by one of Hercules' former subsidiaries to a limited industrial market. The amount and timing of settlements and number of open claims can fluctuate significantly from period to period.

Hercules asbestos-related liability

From the range of estimates, Ashland records the amount it believes to be the best estimate of future payments for litigation defense and claim settlement costs, which generally approximates the mid-point of the estimated range of exposure from model results. Ashland reviews this estimate and related assumptions quarterly and annually updates the results of a non-inflated, non-discounted approximate 50-year model developed with the assistance of HR&A. As a result of the most recent annual update of this estimate, completed during 2015, it was determined that the liability for Hercules asbestos-related claims should be increased by $4 million. Total reserves for asbestos claims were $311 million at September 30, 2015 compared to $329 million at September 30, 2014.

Hercules asbestos-related receivables

For the Hercules asbestos-related obligations, certain reimbursement obligations pursuant to coverage-in-place agreements with insurance carriers exist. As a result, any increases in the asbestos reserve have been partially offset by probable insurance recoveries. Ashland has estimated the value of probable insurance recoveries associated with its asbestos reserve based on management's interpretations and estimates surrounding the available or applicable insurance coverage, including an assumption that all solvent insurance carriers remain solvent. The estimated receivable consists exclusively of domestic insurers. Approximately 40% of the receivable is from insurance companies rated by A.M. Best, all of which have a credit rating of A+ or higher as of September 30, 2015.

As a result of the January 2015 asbestos insurance settlement previously described, Hercules has resolved all disputes with Chartis (AIG) member companies under their existing coverage-in-place agreement for past, present and future Hercules asbestos claims. As a result, during 2015, a $22 million reduction in the insurance receivable balance within the Consolidated Balance Sheets was recorded.

As of September 30, 2015 and 2014, the receivables from insurers amounted to $56 million and $77 million, respectively. During 2015, the annual update of the model used for purposes of valuing the asbestos reserve and its impact on valuation of future recoveries from insurers was completed. This model update resulted in a $1 million increase in the receivable for probable insurance recoveries.

Asbestos litigation cost projection

Projecting future asbestos costs is subject to numerous variables that are extremely difficult to predict. In addition to the significant uncertainties surrounding the number of claims that might be received, other variables include the type and severity of the disease alleged by each claimant, the long latency period associated with asbestos exposure, dismissal rates, costs of medical treatment, the impact of bankruptcies of other companies that are co-defendants in claims, uncertainties surrounding the litigation process from jurisdiction to jurisdiction and from case to case, and the impact of potential changes in legislative or judicial standards. Furthermore, any predictions with respect to these variables are subject to even greater uncertainty as the projection period lengthens. In light of these inherent uncertainties, Ashland believes that the asbestos reserves for Ashland and Hercules

represent the best estimate within a range of possible outcomes. As a part of the process to develop these estimates of future asbestos costs, a range of long-term cost models was developed. These models are based on national studies that predict the number of people likely to develop asbestos-related diseases and are heavily influenced by assumptions regarding long-term inflation rates for indemnity payments and legal defense costs, as well as other variables mentioned previously. Ashland has currently estimated in various models ranging from approximately 40 to 50 year periods that it is reasonably possible that total future litigation defense and claim settlement costs on an inflated and undiscounted basis could range as high as approximately $880 million for the Ashland asbestos-related litigation (current reserve of $409 million) and approximately $560 million for the Hercules asbestos-related litigation (current reserve of $311 million), depending on the combination of assumptions selected in the various models. If actual experience is worse than projected, relative to the number of claims filed, the severity of alleged disease associated with those claims or costs incurred to resolve those claims, Ashland may need to increase further the estimates of the costs associated with asbestos claims and these increases could potentially be material over time.

Environmental remediation and asset retirement obligations

Ashland is subject to various federal, state and local environmental laws and regulations that require environmental assessment or remediation efforts (collectively environmental remediation) at multiple locations. At September 30, 2015, such locations included 85 waste treatment or disposal sites where Ashland has been identified as a potentially responsible party under Superfund or similar state laws, 132 current and former operating facilities (including certain operating facilities conveyed as part of the MAP Transaction) and about 1,225 service station properties, of which 63 are being actively remediated.

Ashland's reserves for environmental remediation and related environmental litigation amounted to $186 million at September 30, 2015 compared to $197 million at September 30, 2014, of which $139 million at September 30, 2015 and $158 million at September 30, 2014 were classified in other noncurrent liabilities on the Consolidated Balance Sheets.

The total reserves for environmental remediation reflect Ashland's estimates of the most likely costs that will be incurred over an extended period to remediate identified conditions for which the costs are reasonably estimable, without regard to any third-party recoveries. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated reserves for environmental remediation. Ashland continues to discount certain environmental sites and regularly adjusts its reserves as environmental remediation continues. Ashland has estimated the value of its probable insurance recoveries associated with its environmental reserve based on management's interpretations and estimates surrounding the available or applicable insurance coverage. At September 30, 2015 and 2014, Ashland's recorded receivable for these probable insurance recoveries were $23 million and $24 million, respectively, of which $16 million and $24 million, respectively, were classified in other noncurrent assets in the Consolidated Balance Sheets.

Environmental remediation reserves are subject to numerous inherent uncertainties that affect Ashland's ability to estimate its share of the costs. Such uncertainties involve the nature and extent of contamination at each site, the extent of required cleanup efforts under existing environmental regulations, widely varying costs of alternate cleanup methods, changes in environmental regulations, the potential effect of continuing improvements in remediation technology, and the number and financial strength of other potentially responsible parties at multiparty sites. Although it is not possible to predict with certainty the ultimate costs of environmental remediation, Ashland currently estimates that the upper end of the reasonably possible range of future costs for identified sites could be as high as approximately $370 million. No individual remediation location is significant, as the largest reserve for any site is approximately 14% or less of the remediation reserve.

OUTLOOK

Business Results

Ashland expects sales for Specialty Ingredients to decline sequentially in the first quarter of 2016, consistent with normal seasonality, to the $490 to $510 million range. EBITDA margins for the quarter are expected to be in the range of 20 to 21 percent. Assuming foreign currency exchange rates remain at current levels, Specialty Ingredients should start to improve its financial comparisons to prior-year periods beginning in the second quarter of fiscal 2016 with comparable comparisons related to the energy market, foreign currency translation and exited product lines expected to begin during the third quarter of 2016.

Ashland expects sales for Performance Materials to decline sequentially in the first quarter of 2016, consistent with normal seasonality, to the $230 to $250 million range. EBITDA margins for the quarter are expected to be in the range of 13.5 to 14.5 percent. The overall Composites results should remain consistent while the Intermediates/Solvents division will likely have lower gross profit margins from aggressive pricing within the market.

Ashland expects sales for Valvoline to decline sequentially in the first quarter of 2016, consistent with normal seasonality, to the $470 to $480 million range. EBITDA margins for the quarter are expected to remain consistent at approximately 20 percent.

Ashland Separation of Valvoline

On September 22, 2015, Ashland announced a plan to separate into two independent, publicly traded companies - one focused on specialty chemicals and the other focused on high-performance lubricants. The announcement followed a comprehensive strategic planning review by Ashland's global leadership team to better understand Ashland's markets, customers and the opportunities for each business to create the most value for shareholders, customers and employees.

Separation planning and key work streams are well under way. Ashland is in the process of designing each company to succeed. The work is being led by a project management team composed of business and resource group leaders from around the world. Ashland is on track to complete the separation consistent with the previously stated timeline.

EFFECTS OF INFLATION AND CHANGING PRICES

Ashland's financial statements are prepared on the historical cost method of accounting in accordance with U.S. GAAP and, as a result, do not reflect changes in the purchasing power of the U.S. dollar. Monetary assets (such as cash, cash equivalents and accounts receivable) lose purchasing power as a result of inflation, while monetary liabilities (such as accounts payable and indebtedness) result in a gain, because they can be settled with dollars of diminished purchasing power. As of September 30, 2015, Ashland's monetary assets exceed its monetary liabilities, leaving it currently more exposed to the effects of future inflation. However, given the recent consistent stability of inflation in the United States in the past several years as well as forward economic outlooks, current inflationary pressures seem moderate.

Certain of the industries in which Ashland operates are capital-intensive, and replacement costs for its plant and equipment generally would substantially exceed their historical costs. Accordingly, depreciation and amortization expense would be greater if it were based on current replacement costs. However, because replacement facilities would reflect technological improvements and changes in business strategies, such facilities would be expected to be more productive than existing facilities, mitigating at least part of the increased expense.

Ashland uses the LIFO method to value a portion of its inventories to provide a better matching of revenues with current costs. However, LIFO values such inventories below their replacement costs during inflationary periods.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements including, without limitation, statements made under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operation" (MD&A), within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended. Ashland has identified some of these forward-looking statements with words such as "anticipates," "believes," "expects," "estimates," "is likely," "predicts," "projects," "forecasts," "may," "will," "should" and "intends" and the negative of these words or other comparable terminology. In addition, Ashland may from time to time make forward-looking statements in its Annual Report to Shareholders, quarterly reports and other filings with the Securities and Exchange Commission (SEC), news releases and other written and oral communications. These forward-looking statements are based on Ashland's expectations and assumptions, as of the date such statements are made, regarding Ashland's future operating performance and financial condition, including the proposed separation of its specialty chemicals and Valvoline businesses, the expected timetable for completing the separation, the future financial and operating performance of each company, strategic and competitive advantages of each company, the leadership of each company, and future opportunities for each company, as well as the economy and other future events or circumstances. Ashland's expectations and assumptions include, without limitation, those mentioned within the MD&A, internal forecasts and analyses of current and future market conditions and trends, management plans and strategies, operating efficiencies and economic conditions (such as prices, supply and demand, cost of raw materials, and the ability to recover raw material cost increases through price increases), and risks and uncertainties associated with the following: the possibility that the proposed separation will not be consummated within the anticipated time period or at all, including as the result of regulatory market or other factors; the potential for disruption to Ashland's business in connection with the proposed separation; the potential that the new Ashland and Valvoline do not realize all of the expected benefits of the separation, Ashland's substantial indebtedness (including the possibility that such indebtedness and related restrictive covenants may adversely affect Ashland's future cash flows, results of operations, financial condition and its ability to repay debt), the impact of acquisitions and/or divestitures Ashland has made or may make (including the possibility that Ashland may not realize the anticipated benefits from such transactions), the global restructuring program (including the possibility that Ashland may not realize the anticipated revenue and earnings growth, cost reductions and other expected benefits from the program); Ashland's ability to generate sufficient cash to finance its stock repurchase plans, severe weather, natural disasters, and legal proceedings and claims (including environmental and asbestos matters). Various risks and uncertainties may cause actual results to differ materially from those stated, projected or implied by any forward-looking statements, including, without limitation, risks and uncertainties affecting Ashland that are contained in "Use

of estimates, risks and uncertainties" in Note A of Notes to Consolidated Financial Statements and in Item 1A of this Annual Report on Form 10-K. Ashland believes its expectations and assumptions are reasonable, but there can be no assurance that the expectations reflected herein will be achieved. Unless legally required, Ashland undertakes no obligation to update any forward-looking statements made in this Annual Report on Form 10-K whether as a result of new information, future events or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Ashland regularly uses derivative instruments to manage its exposure to fluctuations in foreign currencies. All derivative instruments are recognized as either assets or liabilities on the balance sheet and are measured at fair value. Changes in the fair value of all derivatives are recognized immediately in income unless the derivative qualifies as a hedge of future cash flows or a hedge of a net investment in a foreign operation. Gains and losses related to a hedge are either recognized in income immediately to offset the gain or loss on the hedged item, or deferred and recorded in the stockholders' equity section of the Consolidated Balance Sheets as a component of accumulated other comprehensive income and subsequently recognized in the Statements of Consolidated Comprehensive Income when the hedged item affects net income. The ineffective portion of the change in fair value of a hedge is recognized in income immediately. As of September 30, 2015 and 2014, Ashland had not identified any significant credit risk on open derivative contracts. The potential loss from a hypothetical 10% adverse change in foreign currency rates on Ashland's open foreign currency derivative instruments at September 30, 2015 would be a $25 million impact on Ashland's consolidated financial position, results of operations, cash flows or liquidity. Ashland did not transact or have open any significant hedging contracts with respect to commodities or any related raw material requirements as of and for the year ended September 30, 2015.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	Page
Management's report on internal control over financial reporting	F-2
Reports of independent registered public accounting firm	F-3
Consolidated Financial Statements:	
Statements of Consolidated Comprehensive Income	F-6
Consolidated Balance Sheets	F-7
Statements of Consolidated Stockholders' Equity	F-8
Statements of Consolidated Cash Flows	F-9
Notes to Consolidated Financial Statements	F-10
Quarterly financial information	F-56
Five-year selected financial information	F-57

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for the preparation and integrity of the Consolidated Financial Statements and other financial information included in this annual report on Form 10-K. Such financial statements are prepared in accordance with accounting principles generally accepted in the United States. Accounting principles are selected and information is reported which, using management's best judgment and estimates, present fairly Ashland's consolidated financial position, results of operations and cash flows. The other financial information in this annual report on Form 10-K is consistent with the Consolidated Financial Statements.

Ashland's management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Ashland's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Ashland's Consolidated Financial Statements. Ashland's internal control over financial reporting is supported by a code of business conduct which summarizes our guiding values such as obeying the law, adhering to high ethical standards and acting as responsible members of the communities where we operate. Compliance with that Code forms the foundation of our internal control systems, which are designed to provide reasonable assurance that Ashland's assets are safeguarded and its records reflect, in all material respects, transactions in accordance with management's authorization. The concept of reasonable assurance is based on the recognition that the cost of a system of internal control should not exceed the related benefits. Management believes that adequate internal controls are maintained by the selection and training of qualified personnel, by an appropriate division of responsibility in all organizational arrangements, by the establishment and communication of accounting and business policies, and by internal audits.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even when determined to be effective, can only provide reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risks that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Board, subject to stockholder ratification, selects and engages the independent auditors based on the recommendation of the Audit Committee. The Audit Committee, composed of directors who are not members of management, reviews the adequacy of Ashland's policies, procedures, controls and risk management strategies, the scope of auditing and other services performed by the independent auditors, and the scope of the internal audit function. The Committee holds meetings with Ashland's internal auditor and independent auditors, with and without management present, to discuss the findings of their audits, the overall quality of Ashland's financial reporting and their evaluation of Ashland's internal controls. The report of Ashland's Audit Committee can be found in Ashland's 2015 Proxy Statement.

Management assessed the effectiveness of Ashland's internal control over financial reporting as of September 30, 2015. Management conducted its assessment utilizing the framework described in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on this assessment, management believes that Ashland maintained effective internal control over financial reporting as of September 30, 2015.

Ernst & Young LLP, an independent registered public accounting firm, has audited and reported on the Consolidated Financial Statements of Ashland Inc. and Consolidated Subsidiaries as of and for the year ended September 30, 2015 and the effectiveness of Ashland's internal control over financial reporting as of September 30, 2015. The reports of the independent registered public accounting firm are contained in this Annual Report on Form 10-K.

/s/ William A. Wulfsohn
William A. Wulfsohn
Chairman of the Board and Chief Executive Officer

/s/ J. Kevin Willis
J. Kevin Willis
Senior Vice President and Chief Financial Officer

November 20, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Ashland Inc. and Consolidated Subsidiaries

We have audited Ashland Inc. and Consolidated Subsidiaries' internal control over financial reporting as of September 30, 2015, based on criteria established in the Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Ashland Inc. and Consolidated Subsidiaries' 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 Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

A company's internal control over financial reporting is a process designed 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.

In our opinion, Ashland Inc. and Consolidated Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of September 30, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Ashland Inc. and Consolidated Subsidiaries as of September 30, 2015, and the related consolidated statements of comprehensive income, stockholders' equity and cash flows for the year then ended September 30, 2015 of Ashland Inc. and Consolidated Subsidiaries and our report dated November 20, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Cincinnati, Ohio
November 20, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Ashland Inc. and Consolidated Subsidiaries

We have audited the accompanying consolidated balance sheet of Ashland Inc. and Consolidated Subsidiaries as of September 30, 2015, and the related consolidated statements of comprehensive income, stockholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Ashland Inc. and Consolidated Subsidiaries as of September 30, 2015, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Ashland Inc. and Consolidated Subsidiaries' internal control over financial reporting as of September 30, 2015, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated November 20, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Cincinnati, Ohio
November 20, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
of Ashland Inc.

In our opinion, the consolidated balance sheet as of September 30, 2014 and the related consolidated statements of comprehensive income, stockholders' equity and cash flows for each of the two years in the period ended September 30, 2014 present fairly, in all material respects, the financial position of Ashland Inc. and its subsidiaries at September 30, 2014, and the results of their operations and their cash flows for each of the two years in the period ended September 30, 2014, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Cincinnati, Ohio
November 24, 2014

Ashland Inc. and Consolidated Subsidiaries

Statements of Consolidated Comprehensive Income

Years Ended September 30

(In millions except per share data)	2015	2014	2013
Sales	$ 5,387	$ 6,121	$ 6,091
Cost of sales	3,814	4,605	4,304
Gross profit	1,573	1,516	1,787
Selling, general and administrative expense	1,028	1,358	670
Research and development expense	110	114	142
Equity and other income - Note D	23	2	64
Operating income	458	46	1,039
Net interest and other financing expense - Note I	174	166	282
Net gain (loss) on divestitures - Note B	(115)	4	(8)
Income (loss) from continuing operations before income taxes	169	(116)	749
Income tax expense (benefit) - Note L	(22)	(188)	196
Income from continuing operations	191	72	553
Income from discontinued operations (net of tax) - Note C	118	161	130
Net income	$ 309	$ 233	$ 683
PER SHARE DATA - NOTE A			
Basic earnings per share			
Income from continuing operations	$ 2.81	$ 0.94	$ 7.06
Income from discontinued operations	1.73	2.10	1.65
Net income	$ 4.54	$ 3.04	$ 8.71
Diluted earnings per share			
Income from continuing operations	$ 2.78	$ 0.93	$ 6.95
Income from discontinued operations	1.70	2.07	1.62
Net income	$ 4.48	$ 3.00	$ 8.57
COMPREHENSIVE INCOME (LOSS)			
Net income	$ 309	$ 233	$ 683
Other comprehensive income (loss), net of tax			
Unrealized translation gain (loss)	(369)	(160)	37
Pension and postretirement obligation adjustment	(18)	(21)	(5)
Unrealized loss on available-for-sale securities	(11)	—	—
Net change in interest rate hedges	—	—	38
Other comprehensive income (loss)	(398)	(181)	70
Comprehensive income (loss)	$ (89)	$ 52	$ 753

See Notes to Consolidated Financial Statements.

Ashland Inc. and Consolidated Subsidiaries
Consolidated Balance Sheets
At September 30

(In millions)	2015	2014
Assets		
Current assets		
Cash and cash equivalents	$ 1,257	$ 1,393
Accounts receivable (a)	961	1,202
Inventories - Note A	706	765
Deferred income taxes - Note L	155	118
Other assets	169	83
Total current assets	3,248	3,561
Noncurrent assets		
Property, plant and equipment - Note G		
Cost	4,144	4,275
Accumulated depreciation	1,962	1,861
Net property, plant and equipment	2,182	2,414
Goodwill - Note H	2,486	2,643
Intangibles - Note H	1,142	1,309
Restricted investments - Note F	285	—
Asbestos insurance receivable - Note N	180	433
Equity and other unconsolidated investments - Note D	65	81
Other assets - Note J	476	479
Total noncurrent assets	6,816	7,359
Total assets	$ 10,064	$ 10,920
Liabilities and Stockholders' Equity		
Current liabilities		
Short-term debt - Note I	$ 326	$ 329
Current portion of long-term debt - Note I	55	9
Trade and other payables	573	674
Accrued expenses and other liabilities	494	675
Total current liabilities	1,448	1,687
Noncurrent liabilities		
Long-term debt - Note I	3,348	2,911
Employee benefit obligations - Note M	1,076	1,468
Asbestos litigation reserve - Note N	661	701
Deferred income taxes - Note L	89	110
Other liabilities - Note J	405	460
Total noncurrent liabilities	5,579	5,650
Commitments and contingencies - Notes K and N		
Stockholders' equity - Notes O and P		
Common stock, par value $.01 per share, 200 million shares authorized		
Issued 67 million shares in 2015 and 70 million shares in 2014	1	1
Paid-in capital	46	—
Retained earnings	3,281	3,475
Accumulated other comprehensive income (loss)	(291)	107
Total stockholders' equity	3,037	3,583
Total liabilities and stockholders' equity	$ 10,064	$ 10,920

(a) Accounts receivable includes an allowance for doubtful accounts of $11 million in 2015 and $13 million in 2014.

See Notes to Consolidated Financial Statements.

Ashland Inc. and Consolidated Subsidiaries

Statements of Consolidated Stockholders' Equity

(In millions)	Common stock	Paid-in capital	Retained earnings	Accumulated other comprehensive income (loss) (a)	Total
Balance at September 30, 2012	$ 1	$ 647	$ 3,163	$ 218	$ 4,029
Total comprehensive income			683	70	753
Dividends, $1.13 per common share			(88)		(88)
Common shares issued under stock incentive and other plans (b) (c)		9			9
Repurchase of common shares (d)		(150)			(150)
Balance at September 30, 2013	1	506	3,758	288	4,553
Total comprehensive income (loss)			233	(181)	52
Dividends, $1.36 per common share			(103)		(103)
Common shares issued under stock incentive and other plans (b) (c)		35			35
Repurchase of common shares (d)		(541)	(413)		(954)
Balance at September 30, 2014	1	—	3,475	107	3,583
Total comprehensive income (loss)			309	(398)	(89)
Dividends, $1.46 per common share			(98)		(98)
Common shares issued under stock incentive and other plans (b) (c)		46	(8)		38
Repurchase of common shares (d)			(397)		(397)
Balance at September 30, 2015	$ 1	$ 46	$ 3,281	$ (291)	$ 3,037

(a) At September 30, 2015 and 2014, the accumulated other comprehensive loss of $291 million and income of $107 million, respectively, was comprised of unrecognized prior service credits as a result of certain employee benefit plan amendments of $41 million and $59 million, respectively, net unrealized translation loss of $321 million and gain of $48 million, respectively, and net unrealized loss on available for sale securities of $11 million and zero, respectively.

(b) Includes income tax benefits resulting from the exercise of stock options of $8 million in 2015, $23 million in 2014 and $1 million in 2013.

(c) Common shares issued were 441,609, 615,049 and 415,351 for 2015, 2014 and 2013, respectively.

(d) Common shares repurchased were 3,944,356, 7,812,342 and 1,737,744 for 2015, 2014 and 2013, respectively.

See Notes to Consolidated Financial Statements.

Ashland Inc. and Consolidated Subsidiaries

Statements of Consolidated Cash Flows

Years Ended September 30

(In millions)	2015	2014	2013
Cash flows provided (used) by operating activities from continuing operations			
Net income	$ 309	$ 233	$ 683
Income from discontinued operations (net of tax)	(118)	(161)	(130)
Adjustments to reconcile income from continuing operations to cash flows from operating activities			
Depreciation and amortization	341	393	356
Debt issuance cost amortization	18	14	65
Deferred income taxes	(57)	(294)	153
Equity income from affiliates	(15)	(25)	(26)
Distributions from equity affiliates	22	14	11
Stock based compensation expense - Note P	30	34	30
Loss on early retirement of debt	9	—	—
Gain on available-for-sale securities	(3)	—	—
Net loss (gain) on divestitures - Note B	115	(4)	8
Impairments of equity investments and in-process research and development	25	63	41
Pension contributions	(610)	(38)	(124)
Losses (gains) on pension and other postretirement plan remeasurements	255	438	(417)
Change in operating assets and liabilities (a)	(232)	(87)	3
Total cash flows provided by operating activities from continuing operations	89	580	653
Cash flows provided (used) by investing activities from continuing operations			
Additions to property, plant and equipment	(265)	(248)	(264)
Proceeds from disposal of property, plant and equipment	3	3	5
Purchase of operations - net of cash acquired	(13)	—	—
Proceeds (uses) from sale of operations or equity investments	161	92	(13)
Proceeds from sale of available-for-sale securities	315	—	—
Purchase of available-for-sale securities	(315)	—	—
Funds restricted for specific transactions	(320)	(15)	—
Reimbursement from restricted investments	6	—	—
Proceeds from the settlement of derivative instruments	18	—	—
Payments for the settlement of derivative instruments	(7)	—	—
Total cash flows used by investing activities from continuing operations	(417)	(168)	(272)
Cash flows provided (used) by financing activities from continuing operations			
Proceeds from issuance of long-term debt	1,100	—	2,320
Repayment of long-term debt	(623)	(11)	(2,613)
Premium on long-term debt repayment	(9)	—	—
Proceeds (repayment) from short-term debt	(3)	22	(36)
Repurchase of common stock	(397)	(954)	(150)
Debt issuance costs	(9)	—	(38)
Cash dividends paid	(98)	(103)	(88)
Excess tax benefits related to share-based payments	9	12	13
Total cash flows used by financing activities from continuing operations	(30)	(1,034)	(592)
Cash used by continuing operations	(358)	(622)	(211)
Cash provided (used) by discontinued operations			
Operating cash flows	245	63	80
Investing cash flows	24	1,608	(48)
Total cash provided by discontinued operations	269	1,671	32
Effect of currency exchange rate changes on cash and cash equivalents	(47)	(2)	2
Increase (decrease) in cash and cash equivalents	(136)	1,047	(177)
Cash and cash equivalents - beginning of year	1,393	346	523
Cash and cash equivalents - end of year	$ 1,257	$ 1,393	$ 346
Changes in assets and liabilities (a)			
Accounts receivable	$ 261	$ (16)	$ 43
Inventories	39	(4)	106
Trade and other payables	(229)	64	(7)
Other assets and liabilities	(303)	(131)	(139)
Change in operating assets and liabilities	$ (232)	$ (87)	$ 3
Supplemental disclosures			
Interest paid	$ 149	$ 154	$ 182
Income taxes paid	226	88	69

(a) Excludes changes resulting from operations acquired or sold.

See Notes to Consolidated Financial Statements.

NOTE A – SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation and basis of presentation

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP) and U.S. Securities and Exchange Commission regulations. All material intercompany transactions and balances have been eliminated. Additionally, certain prior period data has been reclassified in the Consolidated Financial Statements and accompanying notes to conform to the current period presentation, which includes the adoption of new accounting guidance during the current year related to debt issuance costs presented as a direct deduction from the carrying amount of debt. The Consolidated Financial Statements include the accounts of Ashland and its majority owned subsidiaries. Investments in joint ventures and 20% to 50% owned affiliates where Ashland has the ability to exert significant influence are accounted for under the equity method.

Ashland is composed of three reportable segments: Ashland Specialty Ingredients (Specialty Ingredients), Ashland Performance Materials (Performance Materials) and Valvoline. On July 31, 2014, Ashland completed the sale of the assets and liabilities of Ashland Water Technologies (Water Technologies). As a result of the sale, all prior period operating results and cash flows related to Water Technologies have been reflected as discontinued operations in the Statements of Consolidated Comprehensive Income and Statements of Consolidated Cash Flows. During 2015, Ashland sold certain assets in its portfolio of businesses. See Notes B and Q for additional information on these activities as well as Ashland's current reportable segment results.

Use of estimates, risks and uncertainties

The preparation of Ashland's Consolidated Financial Statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosures of contingent assets and liabilities. Significant items that are subject to such estimates and assumptions include, but are not limited to, long-lived assets (including goodwill and other intangible assets), employee benefit obligations, income taxes and liabilities and receivables associated with asbestos litigation and environmental remediation. Although management bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, actual results could differ significantly from the estimates under different assumptions or conditions.

Ashland's results are affected by domestic and international economic, political, legislative, regulatory and legal actions. Economic conditions, such as recessionary trends, inflation, interest and monetary exchange rates, government fiscal policies and changes in the prices of certain key raw materials, can have a significant effect on operations. While Ashland maintains reserves for anticipated liabilities and carries various levels of insurance, Ashland could be affected by civil, criminal, regulatory or administrative actions, claims or proceedings relating to asbestos, environmental remediation or other matters.

Cash and cash equivalents

Cash and cash equivalents include cash on hand and highly liquid investments maturing within three months after purchase.

Allowance for doubtful accounts

Ashland records an allowance for doubtful accounts as a best estimate of the amount of probable credit losses for accounts receivable. Each month, Ashland reviews this allowance and considers factors such as customer credit, past transaction history with the customer and changes in customer payment terms when determining whether the collection of a receivable is reasonably assured. Past due balances over 90 days and over a specified amount are reviewed individually for collectibility. The allowance for doubtful accounts is adjusted when it becomes probable a receivable will not be recovered.

A progression of activity in the allowance for doubtful accounts is presented in the following table.

(In millions)	2015	2014	2013
Allowance for doubtful accounts - beginning of year	$ 13	$ 12	$ 19
Adjustments to net income	2	5	(4)
Reserves utilized	(3)	(4)	(3)
Other changes	(1)	—	—
Allowance for doubtful accounts - end of year	$ 11	$ 13	$ 12

NOTE A – SIGNIFICANT ACCOUNTING POLICIES (continued)

Inventories

Inventories are carried at the lower of cost or market. Inventories are primarily stated at cost using the weighted-average cost method. In addition, certain chemicals, plastics and lubricants with a replacement cost of $170 million at September 30, 2015 and $232 million at September 30, 2014 are valued at cost using the last-in, first-out (LIFO) method.

The following summarizes Ashland's inventories as of the Consolidated Balance Sheet dates.

(In millions)	2015	2014
Finished products	$ 542	$ 557
Raw materials, supplies and work in process	198	239
LIFO reserves	(34)	(31)
	$ 706	$ 765

A progression of activity in the inventory reserves, which reduce the amounts of finished products and raw materials, supplies and work in process reported, is presented in the following table.

(In millions)	2015	2014	2013
Inventory reserves - beginning of year	$ 53	$ 59	$ 28
Adjustments to net income	9	4	42
Reserves utilized	(6)	(10)	(11)
Dispositions and other changes	(21)	—	—
Inventory reserves - end of year	$ 35	$ 53	$ 59

Property, plant and equipment

The cost of property, plant and equipment is depreciated by the straight-line method over the estimated useful lives of the assets. Buildings are depreciated principally over 25 to 35 years and machinery and equipment principally over 2 to 25 years. Such costs are periodically reviewed for recoverability when impairment indicators are present. Such indicators include, among other factors, operating losses, unused capacity, market value declines and technological obsolescence. Recorded values of asset groups of property, plant and equipment that are not expected to be recovered through undiscounted future net cash flows are written down to current fair value, which generally is determined from estimated discounted future net cash flows (assets held for use) or net realizable value (assets held for sale).

Goodwill and other intangibles

In accordance with U.S. GAAP, Ashland tests goodwill and other indefinite-lived intangible assets for impairment annually as of July 1 and when events and circumstances indicate an impairment may have occurred. Ashland reviews goodwill for impairment based on its identified reporting units, which are defined as operating segments or groupings of businesses one level below the operating segment level. Annually, Ashland tests goodwill for impairment by comparing the carrying value to the estimated fair value of its reporting units, determined using a combination of discounted cash flow models and valuations based on earnings multiples for guideline public companies in each reporting unit's industry peer group, when externally quoted market prices are not readily available. Ashland tests its indefinite-lived intangible assets, principally trademarks and trade names, using a "relief-from-royalty" valuation method compared to the carrying value, while in-process research and development (IPR&D) assets are subject to review through the various stages of the feasibility assessment process. Significant assumptions inherent in the valuation methodologies for goodwill and other intangibles are employed and include, but are not limited to, such estimates as future projected business results, growth rates, the weighted-average cost of capital for a market participant, and royalty and discount rates.

Finite-lived intangible assets principally consist of certain trademarks and trade names, intellectual property, and customer lists. These intangible assets are amortized on a straight-line basis over their estimated useful lives. The cost of trademarks and trade names is amortized principally over 4 to 25 years, intellectual property over 5 to 20 years and customer relationships over 3 to 24 years. Ashland reviews finite-lived intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. Ashland monitors these changes and events on at least a quarterly basis. For further information on goodwill and other intangible assets, see Note H.

Derivative instruments

Ashland regularly uses derivative instruments to manage its exposure to fluctuations in foreign currencies. All derivative instruments are recognized as either assets or liabilities on the balance sheet and are measured at fair value. Changes in the fair value of all derivatives are recognized immediately in income unless the derivative qualifies as a hedge of future cash flows or a hedge of a net investment in a foreign operation. Gains and losses related to a hedge are either recognized in income immediately to offset the gain or loss on the hedged item, or deferred and recorded in the stockholders' equity section of the Consolidated Balance Sheets as a component of accumulated other comprehensive income and subsequently recognized in the Statements of Consolidated Comprehensive Income when the hedged item affects net income. The ineffective portion of the change in fair value of a hedge is recognized in income immediately. For additional information on derivative instruments, see Note F.

Restricted investments

On January 13, 2015, Ashland and Hercules, a wholly owned subsidiary of Ashland that was acquired in 2009, entered into a comprehensive settlement agreement related to certain insurance coverage for asbestos bodily injury claims with Underwriters at Lloyd's, certain London companies and Chartis (AIG) member companies, along with National Indemnity Company and Resolute Management, Inc., under which Ashland and Hercules received a total of $398 million (the January 2015 asbestos insurance settlement). During 2015, Ashland placed $335 million of the settlement funds into a renewable annual trust restricted for the purpose of paying ongoing and future litigation defense and claim settlement costs incurred in conjunction with asbestos claims. These funds are presented primarily as noncurrent assets, with $30 million classified within other current assets in the Consolidated Balance Sheets.

As of September 30, 2015, the funds within the trust were primarily invested in equity and corporate bond investments with a portion maintained in demand deposits. The funds within the trust are classified as available-for-sale securities. Available-for-sale securities are reported at fair value with unrealized gains and losses, net of related deferred income taxes, included in the stockholders' equity section of the Consolidated Balance Sheets as a component of accumulated other comprehensive income. Interest income and realized gains and losses on the available-for-sale securities are reported in the net interest and other financing expense caption in the Statements of Consolidated Comprehensive Income. See Notes F and N for additional information regarding fair value of these investments within the trust and the January 2015 asbestos insurance settlement.

Revenue recognition

Sales generally are recognized when persuasive evidence of an arrangement exists, products are received or services are provided to customers, the sales price is fixed or determinable and collectibility is reasonably assured. For consignment inventory, title and risk of loss are transferred when the products have been consumed or used in the customer's production process. The percentage of Ashland's sales recognized from consignment inventory sales was 3% during 2015, 2014 and 2013. Ashland reports all sales net of tax assessed by qualifying governmental authorities. Certain shipping and handling costs paid by the customer are recorded in sales, while those costs paid by Ashland are recorded in cost of sales.

Expense recognition

Cost of sales include material and production costs, as well as the costs of inbound and outbound freight, purchasing and receiving, inspection, warehousing, internal transfers and all other distribution network costs. Selling, general and administrative expense includes sales and marketing costs, advertising, customer support, environmental remediation, corporate and divisional administrative and other costs. Advertising costs ($62 million in 2015, $63 million in 2014 and $70 million in 2013) and research and development costs ($110 million in 2015, $114 million in 2014 and $142 million in 2013) are expensed as incurred.

Income taxes

Ashland is subject to income taxes in the United States and numerous foreign jurisdictions. Significant judgment in the forecasting of taxable income using historical and projected future operating results is required in determining Ashland's provision for income taxes and the related assets and liabilities. The provision for income taxes includes income taxes paid, currently payable or receivable, and deferred taxes. Under U.S. GAAP, deferred tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities, and are measured using enacted tax rates and laws that are expected to be in effect when the differences reverse. Deferred tax assets are also recognized for the estimated future effects of tax loss carryforwards. The effect on deferred taxes of changes in tax rates is recognized in the period in which the enactment date occurs. Valuation allowances are established when necessary on a jurisdictional basis to reduce deferred tax assets to the amounts expected to be realized. In the event that the actual outcome of future tax consequences differs from Ashland's estimates and assumptions due to changes or future events such as tax legislation, geographic mix of earnings, completion of tax audits or earnings repatriation plans, the resulting change to the provision for income taxes could have a material effect on the Statements of Consolidated Comprehensive Income and Consolidated Balance Sheets. For additional information on income taxes, see Note L.

A progression of activity in the tax valuation allowances for both continuing and discontinued operations is presented in the following table.

(In millions)	2015	2014	2013
Tax valuation allowances - beginning of year	$ 148	$ 166	$ 175
Adjustments to net income	(27)	(5)	(6)
Reserves utilized	(14)	(14)	(2)
Acquisition and other changes	—	1	(1)
Tax valuation allowances - end of year	$ 107	$ 148	$ 166

Asbestos-related litigation

Ashland is subject to liabilities from claims alleging personal injury caused by exposure to asbestos. Such claims result from indemnification obligations undertaken in 1990 in connection with the sale of Riley Stoker Corporation (Riley) and the acquisition of Hercules Incorporated (Hercules) in November 2008. Although Riley, a former subsidiary, was neither a producer nor a manufacturer of asbestos, its industrial boilers contained some asbestos-containing components provided by other companies. Hercules, a wholly-owned subsidiary of Ashland, has liabilities from claims alleging personal injury caused by exposure to asbestos. Such claims typically arise from alleged exposure to asbestos fibers from resin encapsulated pipe and tank products sold by one of Hercules' former subsidiaries to a limited industrial market.

Ashland retained Hamilton, Rabinovitz & Associates, Inc. (HR&A) to assist in developing and annually updating independent reserve estimates for future asbestos claims and related costs given various assumptions. The methodology used by HR&A to project future asbestos costs is based largely on Ashland's recent experience, including claim-filing and settlement rates, disease mix, enacted legislation, open claims, and litigation defense. Ashland's claim experience is compared to the results of previously conducted epidemiological studies estimating the number of people likely to develop asbestos-related diseases. Those studies were undertaken in connection with national analyses of the population expected to have been exposed to asbestos. Using that information, HR&A estimates a range of the number of future claims that may be filed, as well as the related costs that may be incurred in resolving those claims. From the range of estimates, Ashland records the amount it believes to be the best estimate of future payments for litigation defense and claim settlement costs. For additional information on asbestos-related litigation, see Note N.

Environmental remediation

Accruals for environmental remediation are recognized when it is probable a liability has been incurred and the amount of that liability can be reasonably estimated. Such costs are charged to expense if they relate to the remediation of conditions caused by past operations or are not expected to mitigate or prevent contamination from future operations. Liabilities are recorded at estimated cost values based on experience, assessments and current technology, without regard to any third-party recoveries and are regularly adjusted as environmental assessments and remediation efforts continue. For additional information on environmental remediation, see Note N.

Pension and other postretirement benefits

The funded status of Ashland's pension and other postretirement benefit plans is recognized in the Consolidated Balance Sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation at September 30, the measurement date. For defined benefit pension plans, the benefit obligation is the projected benefit obligation (PBO) and for the other postretirement benefit plans, the benefit obligation is the accumulated postretirement benefit obligation (APBO). The PBO represents the actuarial present value of benefits expected to be paid upon retirement based on estimated future compensation levels. The APBO represents the actuarial present value of postretirement benefits attributed to employee services already rendered. The measurement of the benefit obligation is based on Ashland's estimates and actuarial valuations. These valuations reflect the terms of the plans and use participant-specific information such as compensation, age and years of service, as well as certain key assumptions that require significant judgment, including, but not limited to, estimates of discount rates, expected return on plan assets, rate of compensation increases, interest rates and mortality rates. The fair value of plan assets represents the current market value of assets held by an irrevocable trust fund for the sole benefit of participants. For additional information regarding plan assumptions and the current financial position of the pension and other postretirement plans, see Note M.

Ashland recognizes the change in the fair value of plan assets and net actuarial gains and losses annually in the fourth quarter of each fiscal year and whenever a plan is determined to qualify for a remeasurement. The remaining components of pension and other postretirement benefits expense are recorded ratably on a quarterly basis. Pension and other postretirement benefits adjustments charged directly to cost of sales that are applicable to inactive participants are excluded from inventoriable costs. The service cost component of pension and other postretirement benefits costs is allocated to each reportable segment on a ratable basis; while the remaining components of pension and other postretirement benefits costs are recorded to Unallocated and other.

NOTE A – SIGNIFICANT ACCOUNTING POLICIES (continued)

Foreign currency translation

Operations outside the United States are measured primarily using the local currency as the functional currency. Upon consolidation, the results of operations of the subsidiaries and affiliates whose functional currency is other than the U.S. dollar are translated into U.S. dollars at the average exchange rates for the year while assets and liabilities are translated at year-end exchange rates. Adjustments to translate assets and liabilities into U.S. dollars are recorded in the stockholders' equity section of the Consolidated Balance Sheets as a component of accumulated other comprehensive income and are included in net earnings only upon sale or substantial liquidation of the underlying foreign subsidiary or affiliated company.

Stock incentive plans

Ashland recognizes compensation expense for stock incentive plans awarded to key employees and directors, primarily in the form of stock appreciation rights (SARs), restricted stock, performance shares and other non-vested stock awards, that are generally based upon the grant-date fair value over the appropriate vesting period. Ashland utilizes several industry accepted valuation models to determine the fair value. For further information concerning stock incentive plans, see Note P.

Earnings per share

The following is the computation of basic and diluted earnings per share (EPS) from continuing operations. Earnings per share are reported under the treasury stock method. Stock options and SARs for each reported year whose grant price was greater than the market price of Ashland Common Stock at the end of each fiscal year were not included in the computation of income from continuing operations per diluted share because the effect of these instruments would be antidilutive. The total number of these shares outstanding was 0.7 million for 2015 and 0.6 million for 2014 and 2013.

(In millions except per share data)	2015	2014	2013
Numerator			
Numerator for basic and diluted EPS - Income from continuing operations	$ 191	$ 72	$ 553
Denominator			
Denominator for basic EPS - Weighted-average common shares outstanding	68	77	78
Share based awards convertible to common shares	1	1	2
Denominator for diluted EPS - Adjusted weighted-average shares and assumed conversions	69	78	80
EPS from continuing operations			
Basic	$ 2.81	$ 0.94	$ 7.06
Diluted	2.78	0.93	6.95

New accounting pronouncements

In July 2015, the FASB issued accounting guidance to simplify the subsequent measurement of certain inventories by replacing the current lower of cost or market test with a lower of cost and net realizable value test. The guidance applies only to inventories for which cost is determined by methods other than last-in first-out and the retail inventory method. This guidance will become effective prospectively for Ashland on October 1, 2017, with early adoption permitted. Ashland is currently evaluating the new accounting standard and the impact this new guidance will have on Ashland's Consolidated Financial Statements.

In April 2015 and August 2015, the FASB issued accounting guidance to simplify the presentation of debt issuance costs by requiring that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs were not affected by this amendment. The adoption of the new guidance was on a retrospective basis. Ashland elected to early adopt this guidance for debt issuance costs during 2015. As a result, $28 million was presented as long-term debt as of September 30, 2015 and Ashland reclassified $31 million from other noncurrent assets to long-term debt as of September 30, 2014 within the Consolidated Balance Sheets.

In May 2014, the FASB issued accounting guidance outlining a single comprehensive five step model for entities to use in accounting for revenue arising from contracts with customers (ASC 606 Revenue from Contracts with Customers). The new guidance supersedes most current revenue recognition guidance, in an effort to converge the revenue recognition principles within U.S. GAAP. This new guidance also requires entities to disclose certain quantitative and qualitative information regarding the nature, amount, timing and uncertainty of qualifying revenue and cash flows arising from contracts with customers. Entities have

the option of using a full retrospective or a modified retrospective approach to adopt the new guidance. During 2015, the FASB delayed the effective date of this standard by one year. As a result, this guidance now becomes effective for Ashland on October 1, 2018. Ashland is currently evaluating the new accounting standard and the available implementation options the standard allows as well as the impact this new guidance will have on Ashland's Consolidated Financial Statements.

In April 2014, the FASB issued accounting guidance amending the requirements for reporting discontinued operations (ASC 205 Presentation of Financial Statements and ASC 360 Property, Plant and Equipment). This guidance limits the requirement for discontinued operations treatment to the disposal of a component of an entity, or a group of components of an entity, that represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results. Additionally, this new guidance no longer precludes discontinued operations presentation based on continuing involvement or cash flows following the disposal. Ashland adopted this guidance on October 1, 2014, which is applicable only to divestitures subsequent to the adoption date, and has evaluated each divestiture during the current year under this new guidance.

In July 2013, the FASB amended accounting provisions that address the financial statement presentation of tax items eligible for netting (ASC 740 Income Taxes). An unrecognized tax benefit, or a portion of an unrecognized tax benefit, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. This guidance was effective prospectively for Ashland on October 1, 2014, with retrospective application and early adoption permitted. Ashland elected to early adopt this new guidance and apply it retrospectively during 2014. As a result, approximately $49 million as of September 30, 2014, was reclassified in the Consolidated Balance Sheets from other long-term liabilities and offset against deferred tax assets.

In March 2013, the FASB issued accounting guidance related to a parent's accounting for the cumulative translation adjustment upon derecognition of certain subsidiaries or groups of assets within a foreign entity or of an investment in a foreign entity (ASC 830 Foreign Currency Matters). This guidance requires that the cumulative translation adjustment associated with a qualifying derecognized subsidiary or group of assets be immediately recognized within the income statement by the parent company. This guidance became effective for Ashland on October 1, 2014. The adoption of this guidance impacts the Consolidated Financial Statements for divestitures of subsidiaries or assets with cumulative translation.

In February 2013, the FASB issued accounting guidance related to the reporting of amounts reclassified out of accumulated other comprehensive income (ASC 220 Comprehensive Income). This guidance sets forth new disclosure requirements for items reclassified from accumulated other comprehensive income by requiring disclosures for both the changes in accumulated other comprehensive income by component and where the significant items reclassified from accumulated other comprehensive income are classified in the Statements of Consolidated Comprehensive Income. This guidance became effective for Ashland on October 1, 2013 and has been disclosed for all applicable periods presented.

NOTE B – DIVESTITURES

Ashland Separation of Valvoline

On September 22, 2015, Ashland announced that the Board of Directors approved proceeding with a plan to separate Ashland into two independent, publicly traded companies comprising of the new Ashland and Valvoline. Ashland has begun the process to separate its Valvoline business from its Specialty Ingredients and Performance Materials businesses while it finalizes the transaction structure and obtains customary regulatory and other approvals. Ashland intends for the separation, which is subject to final board approval prior to completion, to be tax free for Ashland shareholders. Immediately following the separation, Ashland shareholders will own shares of both the new Ashland and Valvoline. The separation is expected to be completed as soon as practicable, but not before the end of fiscal 2016.

The new Ashland will be a global leader in providing specialty chemical solutions to customers in a wide range of consumer and industrial markets. These markets are currently served by Specialty Ingredients and Performance Materials. Key markets and applications include pharmaceutical, personal care, food and beverage, architectural coatings, adhesives, automotive, construction and energy. Together these businesses generated approximately $3.4 billion in sales for the fiscal year ended September 30, 2015.

Valvoline will focus on building the world's leading engine and automotive maintenance business by providing hands-on expertise to customers in each of its primary market channels: Do-It-Yourself (DIY); Installers; Valvoline Instant Oil Change^{SM}; and International. Valvoline generated sales of $2.0 billion for Ashland during the fiscal year ended September 30, 2015.

Industrial Biocides

During May 2015, Ashland entered into a definitive sale agreement to sell the industrial biocides assets within Specialty Ingredients, which closed on July 1, 2015. As a result of the sale, Ashland received net cash proceeds of approximately $30 million during the fourth quarter of 2015 and recognized a nominal gain before tax and after customary closing costs within the net gain (loss) on divestitures caption within the Statements of Consolidated Comprehensive Income.

The sale of Specialty Ingredients' industrial biocides assets did not qualify for discontinued operations treatment since it did not represent a strategic shift that had or will have a major effect on Ashland's operations and financial results.

Valvoline Car Care Products

In April 2015, Ashland entered into a definitive sale agreement to sell Valvoline's car care product assets for $24 million, which included Car Brite™ and Eagle One™ automotive appearance products. Prior to the sale, Ashland recognized a loss of $26 million before tax in 2015 to recognize the assets at fair value less cost to sell, using Level 2 nonrecurring fair value measurements. The loss is reported within the net gain (loss) on divestitures caption within the Statements of Consolidated Comprehensive Income. The transaction closed on June 30, 2015 and Ashland received net proceeds of $19 million after adjusting for certain customary closing costs and final working capital totals.

The sale of Valvoline's car care product assets did not qualify for discontinued operations treatment since it did not represent a strategic shift that had or will have a major effect on Ashland's operations and financial results.

Valvoline Joint Venture

During April 2015, Ashland sold a Valvoline joint venture equity investment in Venezuela. Prior to the sale, Ashland recognized a $14 million impairment in 2015, for which there was no tax effect, using Level 2 nonrecurring fair value measurements within the equity and other income caption of the Statements of Consolidated Comprehensive Income.

Ashland’s decision to sell the equity investment and the resulting charge recorded during 2015 is reflective of the continued devaluation of the Venezuelan currency (bolivar) based on changes to the Venezuelan currency exchange rate mechanisms during the fiscal year. In addition, the continued lack of exchangeability between the Venezuelan bolivar and U.S. dollar had restricted the joint venture’s ability to pay dividends and obligations denominated in U.S. dollars. These exchange regulations and cash flow limitations, combined with other recent Venezuelan regulations and the impact of declining oil prices on the Venezuelan economy, had significantly restricted Ashland’s ability to conduct normal business operations through the joint venture arrangement. Ashland determined this divestiture does not represent a strategic shift that had or will have a major effect on Ashland's operations and financial results, and thus it does not qualify for discontinued operations treatment.

MAP Transaction

As part of the 2005 transfer of Ashland’s 38% interest in the Marathon Ashland Petroleum joint venture and two other small businesses to Marathon Oil Corporation (Marathon) (the MAP Transaction), Marathon is entitled to the tax deductions for Ashland's future payments of certain contingent liabilities, including asbestos liabilities, related to previously owned businesses of Ashland. Marathon agreed to compensate Ashland for these tax deductions and Ashland established a discounted receivable, which represented the estimated present value of probable recoveries from Marathon for the portion of their future tax deductions. As a result of the January 2015 asbestos insurance settlement, Ashland recorded a $7 million charge during 2015 within the net gain (loss) on divestitures caption of the Statements of Consolidated Comprehensive Income and accordingly reduced the discounted receivable by the same amount. The total MAP receivable remaining as of September 30, 2015 was $9 million. See Note N for more information related to the January 2015 asbestos insurance settlement.

Also, as part of the MAP Transaction, Ashland agreed to sublease certain gas stations to Marathon for a nominal annual amount. During 2013, the third-party investor group that owned these gas stations initiated a sale process that required Ashland to submit an offer, which the investor group accepted. Ashland acquired the gas stations for a total cost of $14 million. In accordance with the MAP Transaction, these gas stations were required to be transferred to Marathon. The $14 million payment to the investor group was recognized by Ashland and recorded within the net gain (loss) on divestitures caption of the Statement of Consolidated Comprehensive Income.

Elastomers

On October 9, 2014, Ashland entered into a definitive agreement to sell the Elastomers division within the Performance Materials reportable segment, which operated a 250-person manufacturing facility in Port Neches, Texas, to Lion Copolymer Holdings, LLC. The Elastomers division, which primarily served the North American replacement tire market, accounted for approximately 5% of Ashland's 2014 sales of $6.1 billion and 18% of Ashland Performance Materials' $1.6 billion in sales in 2014. The sale was completed on December 1, 2014 in a transaction valued at approximately $120 million which was subject to working capital adjustments. The total post-closing adjusted cash proceeds received before taxes by Ashland during 2015 was $105 million, which includes working capital adjustments and transaction costs, as defined in the definitive agreement.

Elastomers' net assets as of November 30, 2014 were $191 million which primarily included accounts receivable, inventory, property, plant and equipment, non-deductible goodwill and other intangibles and payables. Since the net proceeds received were less than book value, Ashland recorded a loss of $86 million pre-tax, using Level 2 nonrecurring fair value measurements, within the net gain (loss) on divestiture caption of the Statements of Consolidated Comprehensive Income during 2015. The related tax

effect was a benefit of $28 million included in the income tax expense (benefit) caption within the Statements of Consolidated Comprehensive Income.

Ashland determined that the sale of Elastomers did not represent a strategic shift that had or will have a major effect on Ashland's operations and financial results. As such, Elastomers' results were included in the Performance Materials reportable segment results of operations and financial position within the Statements of Consolidated Comprehensive Income and Consolidated Balance Sheets, respectively, until its December 1, 2014 sale. Certain indirect corporate costs of $11 million for 2015 were included within the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income that were previously allocated to the Elastomers division and are now reported as selling, general and administrative expense within continuing operations on a consolidated basis within the Unallocated and other segment.

Water Technologies

On July 31, 2014, Ashland sold the Water Technologies business to a fund managed by Clayton, Dubilier & Rice (CD&R) in a transaction valued at approximately $1.8 billion. The total post-closing adjusted cash proceeds received by Ashland during 2014, before taxes, was $1.6 billion, which includes estimates for certain working capital and other post-closing adjustments, as defined in the definitive agreement. Ashland recognized a gain of $92 million after tax, which is included within the discontinued operations caption in the Statement of Consolidated Comprehensive Income for 2014. During 2015, Ashland received $48 million of delayed purchase price funds related to a foreign entity which completed certain regulatory closing requirements. Final settlement of working capital and other post-closing adjustments occurred during 2015 resulting in a payment of approximately $20 million to CD&R.

Since this transaction signified Ashland’s exit from the Water Technologies business, Ashland has classified Water Technologies’ results of operations and cash flows within the Statements of Consolidated Comprehensive Income and Statements of Consolidated Cash Flows as discontinued operations for prior periods presented. Certain indirect corporate costs included within the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income that were previously allocated to the Water Technologies reportable segment did not qualify for classification within discontinued operations and are reported as selling, general and administrative expense within continuing operations on a consolidated basis and within the Unallocated and other segment. These costs were $31 million and $34 million for 2014 and 2013, respectively.

Ashland retained and agreed to indemnify CD&R for certain liabilities of the Water Technologies business arising prior to the closing of the sale, including certain pension and postretirement liabilities, environmental remediation liabilities and certain legacy liabilities relating to businesses disposed or discontinued by the Water Technologies business. Costs directly related to these retained liabilities have been included within the discontinued operations caption of the Statements of Consolidated Comprehensive Income in 2014 and 2013. The ongoing effects of the pension and other postretirement plans for former Water Technologies employees are reported within the Unallocated and other segment.

Ashland provided certain transition services to CD&R for a fee. During 2015 and 2014, Ashland recognized transition service fees of $28 million and $7 million, respectively, within the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income. While the transition services vary in duration depending upon the type of service provided, Ashland continued to reduce costs as the transition services were completed. See Note C for further information on the results of operations of Water Technologies for all periods presented.

Casting Solutions joint venture

During 2014, Ashland, in conjunction with its partner, initiated a process to sell the ASK Chemicals GmbH (ASK) joint venture, in which Ashland had 50% ownership. As part of the sale process, Ashland determined during 2014 that the fair value of its investment in the ASK joint venture was less than the carrying value and that an other than temporary impairment had occurred. As a result, Ashland recognized an impairment charge of $50 million related to its investment in the ASK joint venture. The charge was recognized within the equity and other income caption of the Statements of Consolidated Comprehensive Income.

On June 30, 2014, Ashland, in conjunction with its partner, sold the ASK joint venture to investment funds affiliated with Rhône Capital, LLC (Rhône), a London and New York-based private equity investment firm. From the sale, total pre-tax proceeds to the sellers, which were split evenly between Ashland and its partner, under the terms of the 50/50 joint venture, were $205 million, which included $176 million in cash and a $29 million note from Rhône due in calendar year 2022.

NOTE C – DISCONTINUED OPERATIONS

In previous periods, Ashland has divested certain businesses that have qualified as discontinued operations. The operating results from these divested businesses and subsequent adjustments related to ongoing assessments of certain retained liabilities and tax items have been recorded within the discontinued operations caption in the Statements of Consolidated Comprehensive Income for all periods presented and are discussed further within this note.

Ashland is subject to liabilities from claims alleging personal injury caused by exposure to asbestos. Such claims result primarily from indemnification obligations undertaken in 1990 in connection with the sale of Riley, a former subsidiary, which qualified as a discontinued operation and from the acquisition during 2009 of Hercules, a wholly-owned subsidiary of Ashland. Adjustments to the recorded litigation reserves and related insurance receivables are recorded within the discontinued operations caption and continue periodically. During 2015, Ashland recorded an after-tax gain of $120 million within discontinued operations due to the January 2015 asbestos insurance settlement. See Note N for further discussion of Ashland's asbestos-related activity.

As previously described in Note B, on July 31, 2014, Ashland completed the sale of the Water Technologies business to CD&R. Sales recognized for the ten month period Water Technologies was still owned by Ashland in 2014 were $1.5 billion and $1.7 billion in 2013. The previous results of operation related to Water Technologies have been reflected as discontinued operations in the Statements of Consolidated Comprehensive Income.

On March 31, 2011, Ashland completed the sale to Nexeo Solutions, LLC of substantially all of the assets and certain liabilities of its global distribution business, which previously comprised the Ashland Distribution (Distribution) reportable segment. Ashland determined that this sale qualified as a discontinued operation, in accordance with U.S. GAAP, since Ashland does not have significant continuing involvement in the Distribution business. Ashland made subsequent adjustments to the discontinued operations caption for Distribution during 2015 and 2013.

On August 28, 2006, Ashland completed the sale of the stock of Ashland Paving And Construction, Inc. (APAC) for $1.3 billion. The sale qualified as a discontinued operation, and as a result, the previous operating results related to APAC have been reflected as discontinued operations in the Statements of Consolidated Comprehensive Income. Ashland has made subsequent adjustments to the gain on the sale of APAC, primarily relating to the tax effects of the sale, during 2015, 2014 and 2013.

Due to the ongoing assessment of certain matters associated with previous divestitures, subsequent adjustments to these divestitures may continue in future periods in the discontinued operations caption in the Statements of Consolidated Comprehensive Income. Components of amounts reflected in the Statements of Consolidated Comprehensive Income related to discontinued operations are presented in the following table for each of the years ended September 30.

(In millions)	2015	2014	2013
Income (loss) from discontinued operations			
Asbestos-related litigation matters	$ 132	$ 5	$ (3)
Water Technologies	(3)	84	202
Distribution	(3)	—	(9)
Gain on disposal of discontinued operations			
Water Technologies	4	148	—
Income before taxes	130	237	190
Income tax benefit (expense)			
Benefit (expense) related to income (loss) from discontinued operations			
Asbestos-related litigation reserves and expenses	(22)	1	5
Water Technologies	2	(25)	(78)
Distribution	1	—	3
Benefit (expense) related to gain (loss) on disposal of discontinued operations			
Water Technologies	3	(56)	—
Distribution	3	—	—
APAC	1	4	10
Income from discontinued operations (net of taxes)	$ 118	$ 161	$ 130

NOTE D – UNCONSOLIDATED AFFILIATES

Summarized financial information for companies accounted for on the equity method is presented in the following table, along with a summary of the amounts recorded in Ashland's Consolidated Financial Statements. These amounts exclude any applicable affiliates from the Water Technologies business for prior periods presented since it was divested during 2014 and in accordance with provisions within U.S. GAAP the results of this business have been reclassified to discontinued operations in the Statements of Consolidated Comprehensive Income. The results of operations and amounts recorded by Ashland as of and for the years ended September 30, 2015 and 2014 only include results for the Valvoline joint venture within Venezuela and the ASK joint venture prior to their divestitures. See Note B for further information on these divestitures in 2015 and 2014.

At September 30, 2015 and 2014, Ashland's retained earnings included $54 million and $73 million, respectively, of undistributed earnings from unconsolidated affiliates accounted for on the equity method. The summarized financial information for all companies accounted for on the equity method by Ashland is as of and for the years ended September 30, 2015, 2014 and 2013, respectively.

(In millions)	2015	2014	2013
Financial position			
Current assets	$ 211	$ 292	
Current liabilities	(54)	(98)	
Working capital	157	194	
Noncurrent assets	40	45	
Noncurrent liabilities	(1)	(1)	
Stockholders' equity	$ 196	$ 238	
Results of operations			
Sales	$ 398	$ 966	$ 1,181
Income from operations	57	74	79
Net income	31	63	53
Amounts recorded by Ashland			
Investments and advances	$ 65	$ 81	$ 213
Equity income (loss) (a)	1	(25)	26
Distributions received	22	14	11

(a) The results in 2015 and 2014 include a $14 million and $50 million impairment on the Valvoline joint venture in Venezuela and the ASK joint venture, respectively.

NOTE E – RESTRUCTURING ACTIVITIES

Ashland periodically implements company-wide restructuring programs related to acquisitions, divestitures and other cost reduction programs in order to enhance profitability through streamlined operations and an improved overall cost structure for each business.

Severance costs

During 2014, Ashland announced a global restructuring program to streamline the resources used across the organization. As part of this global restructuring program, Ashland announced a voluntary severance offer (VSO) to certain U.S. employees. Approximately 400 employees were formally approved for the VSO. Additionally, during 2014, an involuntary program for employees was also initiated as part of the global restructuring program. Substantially all payments related to the VSO and involuntary programs were paid by the end of fiscal year 2015. The VSO and involuntary programs resulted in expense of $95 million being recognized during 2014, with $13 million being recorded within the cost of sales caption and $82 million being recorded within the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income. In addition, the employee reductions resulted in a pension curtailment being recorded during 2014. See Note M for further information. As of September 30, 2015 and 2014, the remaining restructuring reserve for the global restructuring program was $7 million and $53 million, respectively.

As of September 30, 2015 and 2014, the remaining $1 million and $3 million, respectively, in restructuring reserves for other previously announced programs principally consisted of expected future severance payments for programs implemented during 2011. Substantially all of these payments will be paid by the end of fiscal year 2016.

NOTE E – RESTRUCTURING ACTIVITIES (continued)

Facility costs

The costs related to this reserve primarily relate to lease abandonment charges incurred due to the exit from office facilities obtained as part of the Hercules acquisition. During 2014, Ashland incurred an additional $4 million lease abandonment charge related to its exit from a Hercules related office facility. The costs related to the reserve will be paid over the remaining lease term through May 2016. As of September 30, 2015 and 2014, the remaining restructuring reserve for all qualifying facility costs totaled $3 million and $9 million, respectively.

The following table details at September 30, 2015, 2014 and 2013, the amount of restructuring reserves related to the programs discussed above, and the related activity in these reserves during 2015, 2014 and 2013. The severance reserves are included in accrued expenses and other liabilities in the Consolidated Balance Sheet for all periods presented. As of September 30, 2015, facility cost reserves are included in accrued expenses and other liabilities in the Consolidated Balance Sheet, while these reserves were primarily within other noncurrent liabilities as of September 30, 2014.

(In millions)	Severance	Facility costs	Total
Balance as of September 30, 2012	$ 29	$ 15	$ 44
Reserve adjustments	9	—	9
Utilization (cash paid)	(21)	(7)	(28)
Balance as of September 30, 2013	17	8	25
Restructuring reserves	95	4	99
Reserve adjustments	(4)	—	(4)
Utilization (cash paid)	(52)	(3)	(55)
Balance as of September 30, 2014	56	9	65
Reserve adjustments	(3)	(2)	(5)
Utilization (cash paid)	(45)	(4)	(49)
Balance as of September 30, 2015	$ 8	$ 3	$ 11

Specialty Ingredients Restructuring

During 2015, Specialty Ingredients committed to a restructuring plan within an existing manufacturing facility. As a result, restructuring charges of $23 million were recorded within the cost of sales caption of the Statements of Consolidated Comprehensive Income. As of September 30, 2015, the remaining restructuring reserve related to severance for the Specialty Ingredients manufacturing facility totaled $13 million. The restructuring plan is expected to be completed during fiscal 2016.

NOTE F – FAIR VALUE MEASUREMENTS

As required by U.S. GAAP, Ashland uses applicable guidance for defining fair value, the initial recording and periodic remeasurement of certain assets and liabilities measured at fair value and related disclosures for instruments measured at fair value. Fair value accounting guidance establishes a fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). An instrument's categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the instrument's fair value measurement. The three levels within the fair value hierarchy are described as follows.

Level 1 – Observable inputs such as unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 – Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. These include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3 – Unobservable inputs for the asset or liability for which there is little, if any, market activity at the measurement date. Unobservable inputs reflect Ashland's own assumptions about what market participants would use to price the asset or liability. The inputs are developed based on the best information available in the circumstances, which might include Ashland's own financial data such as internally developed pricing models, discounted cash flow methodologies, as well as instruments for which the fair value determination requires significant management judgment.

For assets that are measured using quoted prices in active markets (Level 1), the total fair value is the published market price per unit multiplied by the number of units held without consideration of transaction costs. Assets and liabilities that are measured

using significant other observable inputs (Level 2) are primarily valued by reference to quoted prices of similar assets or liabilities in active markets, adjusted for any terms specific to that asset or liability. For all other assets and liabilities for which unobservable inputs are used (Level 3), fair value is derived through the use of fair value models, such as a discounted cash flow model or other standard pricing models that Ashland deems reasonable.

The following table summarizes financial asset instruments subject to recurring fair value measurements as of September 30, 2015. For additional information on fair value hierarchy measurements of pension plan asset holdings, see Note M.

(In millions)	Carrying value	Total fair value	Quoted prices in active markets for identical assets Level 1	Significant other observable inputs Level 2	Significant unobservable inputs Level 3
Assets					
Cash and cash equivalents	$ 1,257	$ 1,257	$ 1,257	$ —	$ —
Restricted investments (a)	315	315	315	—	—
Deferred compensation investments (b)	180	180	40	140	—
Investments of captive insurance company (b)	4	4	4	—	—
Foreign currency derivatives	13	13	—	13	—
Total assets at fair value	$ 1,769	$ 1,769	$ 1,616	$ 153	$ —
Liabilities					
Foreign currency derivatives	$ 16	$ 16	$ —	$ 16	$ —
Total liabilities at fair value	$ 16	$ 16	$ —	$ 16	$ —

(a) Included in restricted investments and $30 million within other current assets in the Consolidated Balance Sheets.
(b) Included in other noncurrent assets in the Consolidated Balance Sheets.

The following table summarizes financial asset instruments subject to recurring fair value measurements as of September 30, 2014.

(In millions)	Carrying value	Total fair value	Quoted prices in active markets for identical assets Level 1	Significant other observable inputs Level 2	Significant unobservable inputs Level 3
Assets					
Cash and cash equivalents	$ 1,393	$ 1,393	$ 1,393	$ —	$ —
Deferred compensation investments (a)	184	184	45	139	—
Investments of captive insurance company (a)	3	3	3	—	—
Foreign currency derivatives	11	11	—	11	—
Total assets at fair value	$ 1,591	$ 1,591	$ 1,441	$ 150	$ —
Liabilities					
Foreign currency derivatives	$ 9	$ 9	$ —	$ 9	$ —
Total liabilities at fair value	$ 9	$ 9	$ —	$ 9	$ —

(a) Included in other noncurrent assets in the Consolidated Balance Sheets.

Restricted investments

As discussed in Note A, Ashland maintains certain investments in a restrictive renewable annual trust for the purpose of paying future asbestos indemnity and defense costs. The investments are designated as available-for-sale securities, classified as Level

1 measurements within the fair value hierarchy. These securities were classified primarily as noncurrent restricted investment assets, with $30 million classified within other current assets, in the Consolidated Balance Sheets. The following table provides a summary of the available-for-sale securities portfolio for the fiscal year ended September 30, 2015:

(In millions) As of September 30, 2015	Original Cost	Investment Income (a)	Unrealized gain	Unrealized loss	Disbursements	Fair Value
Demand deposit	$ 20	3	$ —	$ —	(6)	$ 17
Equity mutual fund	195	—	—	(14)	—	181
Corporate bond mutual fund	120	—	—	(3)	—	117
Total	$ 335	3	$ —	$ (17)	(6)	$ 315

(a) Investment income for the demand deposit includes interest income as well as dividend income transferred from the equity and corporate bond mutual funds.

Investment income of $3 million was recognized during 2015 within net interest and other financing expense in the Statements of Consolidated Comprehensive Income. The unrealized losses, less than twelve months in duration, were recognized within accumulated other comprehensive income (AOCI). At September 30, 2015, Ashland considered the decline in market value of its restricted investment portfolio to be temporary in nature and does not consider any of its investments other-than-temporarily impaired. Ashland invests in highly-rated mutual funds comprised principally of investment grade securities. No realized gain or loss was reclassified out of AOCI and no other-than-temporary impairment was recognized in AOCI during 2015.

Deferred compensation investments

Deferred compensation investments consist of Level 1 and Level 2 measurements within the fair value hierarchy. Level 1 investments consist primarily of fixed income U.S. government bonds while Level 2 investments are comprised primarily of a guaranteed interest fund, a common stock index fund and an intermediate government bond fund.

Derivative and hedging activities

Currency hedges

Ashland conducts business in a variety of foreign currencies. Accordingly, Ashland regularly uses foreign currency derivative instruments to manage exposure on certain transactions denominated in foreign currencies to curtail potential earnings volatility effects of certain assets and liabilities, including short-term inter-company loans, denominated in currencies other than Ashland's functional currency of an entity. These derivative contracts generally require exchange of one foreign currency for another at a fixed rate at a future date and generally have maturities of less than twelve months. All contracts are marked-to-market with net changes in fair value recorded within the selling, general and administrative expense caption. The impacts of these contracts were largely offset by gains and losses resulting from the impact of changes in exchange rates on transactions denominated in non-functional currencies. The following table summarizes the currency hedge gains and losses recognized during 2015, 2014 and 2013 within the Statements of Consolidated Comprehensive Income.

(In millions)	2015	2014	2013
Foreign currency derivative gains (losses)	$ (17)	$ (7)	$ 1

The following table summarizes the fair values of the outstanding foreign currency derivatives as of September 30, 2015 and 2014 included in accounts receivable and accrued expenses and other liabilities of the Consolidated Balance Sheets.

(In millions)	2015	2014
Foreign currency derivative assets	$ 5	$ 2
Notional contract values	192	88
Foreign currency derivative liabilities	$ 16	$ 4
Notional contract values	673	281

Net investment hedges

During 2015 and 2014, Ashland entered into foreign currency contracts in order to manage the foreign currency exposure of the net investment in certain foreign operations. These foreign currency contracts were primarily the result of certain proceeds

from the sale of Water Technologies being received in non-U.S. denominated currencies during 2014 and ongoing management of the volatility in foreign currency exchange rates. Ashland designated the foreign currency contracts as hedges of net investment in its foreign subsidiaries. As a result, Ashland records these hedges at fair value using forward rates, with the effective portion of the gain or loss reported as a component of the cumulative translation adjustment within AOCI and subsequently recognized in the Statements of Consolidated Income when the hedged item affects net income. During 2015, certain foreign currency contracts were settled. These settlements resulted in net gains recorded within the cumulative translation adjustment within AOCI of $11 million for 2015.

As of September 30, 2015 and 2014, the total notional value of foreign currency contracts equaled $175 million and $206 million, respectively. The fair value of Ashland's net investment hedge assets and liabilities are calculated using forward rates. Accordingly, these instruments are deemed to be Level 2 measurements within the fair value hierarchy. Counterparties to these net investment hedges are highly rated financial institutions which Ashland believes carry only a nominal risk of nonperformance. The following table summarizes the fair value of the outstanding net investment hedge instruments as of September 30, 2015 and 2014.

(In millions)	Consolidated balance sheet caption	2015	2014
Net investment hedge assets	Accounts receivable	$ 8	$ 9
Net investment hedge liabilities (a)	Accrued expenses and other liabilities	—	5

(a) Fair values of $0 denote a value less than $1 million.

The following table summarizes the change in the unrealized gain on the net investment hedge instruments recognized within the cumulative translation adjustment within AOCI during 2015 and 2014. No portion of the gain was reclassified to income during 2015 and 2014. There was no hedge ineffectiveness with these instruments during 2015 and 2014.

(In millions)	2015	2014
Change in unrealized gain in AOCI	$ 8	$ 4
Tax impact of change in unrealized gain in AOCI	(2)	(3)

Interest rate hedges

During 2011, Ashland entered into interest rate swap agreements in order to manage the variable interest rate risk associated with term loans A and B that were borrowed in conjunction with the August 2011 acquisition of International Specialty Products Inc. (ISP). These instruments were designated as cash flow hedges whereby Ashland recorded these hedges at fair value, with the effective portion of the gain or loss reported as a component of AOCI and subsequently recognized in the Statements of Consolidated Comprehensive Income when the hedged item affected net income. Ashland terminated the interest rate swap agreements in conjunction with the repayment of term loans A and B during 2013, resulting in a charge of $52 million included in the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income during 2013.

During 2013, Ashland reclassified a loss of $65 million from AOCI to the Statements of Consolidated Comprehensive Income. The losses reclassified to the Statements of Consolidated Comprehensive Income were recorded in the net interest and other financing expense caption. Additionally, an unrealized loss of $3 million on interest rate hedges was recognized in AOCI during 2013.

Other financial instruments

At September 30, 2015 and 2014, Ashland’s long-term debt (including current portion and excluding debt issuance cost discounts) had a carrying value of $3,431 million and $2,951 million, respectively, compared to a fair value of $3,484 million and $3,102 million, respectively. The fair values of long-term debt are based on quoted market prices or, if market prices are not available, the present values of the underlying cash flows discounted at Ashland’s incremental borrowing rates, and are deemed to be Level 2 measurements within the fair value hierarchy.

NOTE G – PROPERTY, PLANT AND EQUIPMENT

The following table describes the various components of property, plant and equipment within the Consolidated Balance Sheets.

(In millions)	2015	2014
Land	$ 202	$ 228
Buildings	710	730
Machinery and equipment	2,957	3,049
Construction in progress	275	268
Total property, plant and equipment (gross)	4,144	4,275
Accumulated depreciation	(1,962)	(1,861)
Total property, plant and equipment (net)	$ 2,182	$ 2,414

The following table summarizes various property, plant and equipment charges included within the Statements of Consolidated Comprehensive Income.

(In millions)	2015	2014	2013
Depreciation	$ 263	$ 304	$ 268
Capitalized interest	2	1	1

Depreciation during 2015 includes $6 million of accelerated depreciation related to the restructuring plan of an existing manufacturing facility within the Specialty Ingredients reportable segment. These charges were recorded within the cost of sales caption of the Statements of Consolidated Comprehensive Income. During 2014, depreciation included $36 million of accelerated depreciation and asset impairment, including a $19 million impairment related to the impairment of a product line within the Specialty Ingredients reportable segment. This charge was recorded within the cost of sales caption of the Statements of Consolidated Comprehensive Income. The remaining $17 million relates to accelerated depreciation associated with plant closures within the Performance Materials reportable segment. During 2013, there was $2 million of accelerated depreciation.

NOTE H – GOODWILL AND OTHER INTANGIBLES

Goodwill

Ashland reviews goodwill and indefinite-lived intangible assets for impairment annually or when events and circumstances indicate an impairment may have occurred. This annual assessment is performed as of July 1 and consists of Ashland determining each reporting unit's current fair value compared to its current carrying value. Subsequent to the business realignment during 2014 and the December 1, 2014 sale of the Elastomers division, which was previously a reporting unit, Ashland determined that its reporting units for the allocation of goodwill include the Specialty Ingredients and Valvoline reportable segments, and the Composites and Intermediates/Solvents reporting units within the Performance Materials reportable segment.

Prior to this business realignment in 2014, the reporting units consisted of the Specialty Ingredients and Valvoline reportable segments, and the Composites and Adhesives reporting unit and the Elastomers reporting unit within the Performance Materials reportable segment. As a result of the business realignment in 2014, goodwill was reallocated using a relative fair value approach and Ashland performed an assessment to determine if an impairment existed. Upon completion of this assessment, Ashland concluded that no impairment existed.

Ashland makes various estimates and assumptions in determining the estimated fair values of those units through the use of a combination of discounted cash flow models and valuations based on earnings multiples for guideline public companies in each reporting unit's industry peer group. Discounted cash flow models are highly reliant on various assumptions. Significant assumptions Ashland utilized in these models for the current year included: projected business results and future industry direction, long-term growth factors and weighted-average cost of capital. Ashland uses assumptions that it deems to be reasonable estimates of likely future events and compares the total fair values of each reporting unit to Ashland's market capitalization, and implied control premium, to determine if the fair values are reasonable compared to external market indicators. Subsequent changes in these key assumptions could affect the results of future goodwill impairment reviews. In conjunction with the July 1, 2015 annual assessment of goodwill, Ashland's valuation techniques did not indicate any impairment.

Ashland's assessment of an impairment charge on any of these assets currently classified as having indefinite lives, including goodwill, could change in future periods if any or all of the following events were to occur with respect to a particular reporting

unit: a significant change in projected business results, a divestiture decision, increase in Ashland's weighted-average cost of capital rates, decrease in growth rates or other assumptions, economic deterioration that is more severe or of a longer duration than anticipated, or another significant economic event.

The following is a progression of goodwill by reportable segment for the years ended September 30, 2015 and 2014.

(In millions)	Specialty Ingredients	Performance Materials (a)	Valvoline	Total
Balance at September 30, 2013	$ 2,231	$ 311	$ 167	$ 2,709
Business realignment adjustment (b)	(39)	39	—	—
Currency translation	(63)	(4)	1	(66)
Balance at September 30, 2014	2,129	346	168	2,643
Acquisitions (c)	—	—	3	3
Divestitures (d)	(10)	(10)	(1)	(21)
Currency translation	(115)	(23)	(1)	(139)
Balance at September 30, 2015	$ 2,004	$ 313	$ 169	$ 2,486

(a) As of September 30, 2015, goodwill consisted of $142 million for the Composites reporting unit and $171 million for the Intermediates/Solvents reporting unit.

(b) Business realignment adjustment represents the reallocation of goodwill during 2014 as a result of the transfer of Adhesives and Intermediates/Solvents between the Specialty Ingredients and Performance Materials reportable segments. In the fourth quarter of 2014, an error of $32 million was identified in the amount of goodwill associated with Intermediates/Solvents that was originally reallocated in the third quarter of 2014. The amount of goodwill transferred from Specialty Ingredients to Performance Materials was revised from $71 million to $39 million to correct the error. Ashland does not believe that this revision was material to the previously filed financial information.

(c) Relates to Valvoline Instant Oil Change℠ acquisitions during 2015.

(d) Divestiture caption represents the amounts of goodwill for the sale of Elastomers, Valvoline car care products and industrial biocides. See Note B for additional information.

Other intangible assets

Intangible assets principally consist of trademarks and trade names, intellectual property, customer relationships and IPR&D. Intangible assets classified as finite are amortized on a straight-line basis over their estimated useful lives. The cost of trademarks and trade names is amortized principally over 4 to 25 years, intellectual property over 5 to 20 years and customer relationships over 3 to 24 years.

IPR&D and certain intangible assets within trademarks and trade names have been classified as indefinite-lived and had a balance of $311 million and $322 million as of September 30, 2015 and 2014, respectively. During 2015, 2014 and 2013 there was a decrease in indefinite-lived intangible assets of $11 million, $13 million and $41 million, respectively, which represent impairments incurred related to certain IPR&D assets associated with the acquisition of ISP, classified within the research and development expense caption of the Statements of Consolidated Comprehensive Income. These impairments represent Level 2 nonrecurring fair value measurements. Ashland has started amortizing remaining IPR&D assets during fiscal 2016 since the technology was commercialized during this period.

In accordance with U.S. GAAP, Ashland annually reviews indefinite-lived intangible assets for possible impairment or whenever events or changes in circumstances indicate that carrying amounts may not be recoverable. In conjunction with the July 1, 2015 annual assessment of indefinite-lived intangible assets, Ashland's models did not indicate any additional impairment for indefinite-lived intangible assets. Intangible assets were comprised of the following as of September 30, 2015 and 2014.

NOTE H – GOODWILL AND OTHER INTANGIBLES (continued)

(In millions)	2015 Gross carrying amount	2015 Accumulated amortization	2015 Net carrying amount	2014 Gross carrying amount	2014 Accumulated amortization	2014 Net carrying amount
Definite-lived intangible assets						
Trademarks and trade names (a)	$ 48	$ (41)	$ 7	$ 72	$ (49)	$ 23
Intellectual property (b)	813	(266)	547	827	(226)	601
Customer relationships (c)	424	(147)	277	481	(118)	363
Total definite-lived intangible assets	1,285	(454)	831	1,380	(393)	987
Indefinite-lived intangible assets						
IPR&D	8	—	8	19	—	19
Trademarks and trade names	303	—	303	303	—	303
Total intangible assets	$ 1,596	$ (454)	$ 1,142	$ 1,702	$ (393)	$ 1,309

(a) Divested trademarks and trade names during 2015 had gross carrying amounts of $6 million, $7 million and $11 million for Elastomers, Valvoline car care products and industrial biocides, respectively, and accumulated amortization of $5 million, $3 million and $3 million, respectively.
(b) Divested intellectual property during 2015 had a gross carrying amount of $18 million with $5 million of accumulated amortization for Elastomers.
(c) Divested customer relationships during 2015 had a gross carrying amount and accumulated amortization of $1 million each for Valvoline car care products.

Amortization expense recognized on intangible assets was $78 million for 2015, $89 million for 2014 and $88 million for 2013, and is primarily included in the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income. As of September 30, 2015, all of Ashland's intangible assets that had a carrying value were being amortized except for IPR&D and certain trademarks and trade names that have been determined to have indefinite lives. Estimated amortization expense for future periods is $78 million in 2016, $78 million in 2017, $78 million in 2018, $74 million in 2019 and $73 million in 2020. The amortization expense for future periods is an estimate. Actual amounts may change from such estimated amounts due to fluctuations in foreign currency exchange rates, additional intangible asset acquisitions and divestitures, potential impairment, accelerated amortization, or other events.

NOTE I – DEBT

The following table summarizes Ashland's current and long-term debt at September 30, 2015 and 2014.

(In millions)	2015	2014
4.750% notes, due 2022	$ 1,120	$ 1,120
Term Loan, due 2020	1,086	—
3.875% notes, due 2018	700	700
6.875% notes, due 2043	376	376
Accounts receivable securitization (a)	190	255
6.50% junior subordinated notes, due 2029	136	134
Revolving credit facility	110	45
Other international loans, interest at a weighted-average rate of 6.2% at September 30, 2015 (5.3% to 9.5%)	25	29
Medium-term notes, due 2019, interest of 9.4% at September 30, 2015	5	14
3.000% notes, due 2016	—	600
Other (b)	(19)	(24)
Total debt	3,729	3,249
Short-term debt	(326)	(329)
Current portion of long-term debt	(55)	(9)
Long-term debt (less current portion and debt issuance cost discounts)	$ 3,348	$ 2,911

(a) During 2015, the potential funding for qualified receivables was reduced from $275 million to $250 million.
(b) Other includes $28 million and $31 million of debt issuance cost discounts as of September 30, 2015 and 2014, respectively.

At September 30, 2015, Ashland's total debt had an outstanding principal balance of $3,907 million, discounts of $150 million and debt issuance costs of $28 million. The scheduled aggregate maturities of debt for the next five fiscal years are as follows: $381 million in 2016, $69 million in 2017, $810 million in 2018, $143 million in 2019 and $715 million in 2020.

Senior notes and senior credit facilities

Senior notes refinancing and 2015 Senior Credit Agreement

During June of 2015, Ashland completed certain refinancing transactions related to the $600 million 3.000% senior notes due in 2016 (2016 senior notes). Ashland commenced and completed a cash tender offer to purchase for cash any and all of its outstanding 2016 senior notes. At the close of the tender offer, $550 million aggregate principal amount of the 2016 senior notes was tendered by note holders, representing approximately 92% of the outstanding 2016 senior notes, which have been purchased by Ashland. Subsequently, Ashland redeemed the remaining balance of the 2016 senior notes of $50 million on July 23, 2015.

In connection with the tender offer and redemption, in June 2015, Ashland entered into a new Credit Agreement (the 2015 Senior Credit Agreement). The 2015 Senior Credit Agreement replaced the $1.2 billion senior unsecured revolving credit facility (the 2013 Senior Credit Facility), and was comprised of a new five-year senior unsecured revolving credit facility in an aggregate amount of $1.2 billion (the 2015 revolving credit facility), which includes a $250 million letter of credit sublimit and a $100 million swing line loan sublimit, and a five-year senior unsecured term loan facility in an aggregate principal amount of $1.1 billion (the term loan facility). The 2015 Senior Credit Agreement is not guaranteed, is unsecured and can be prepaid at any time without premium or penalty.

At Ashland's option, borrowings under the 2015 revolving credit facility will bear interest at either LIBOR or an alternate base rate, in each case plus the applicable interest rate margin. The loans' interest rate will fluctuate between LIBOR plus 1.375% per annum and LIBOR plus 2.50% per annum (or between the alternate base rate plus 0.375% per annum and the alternate base rate plus 1.50% per annum), based upon Ashland's corporate credit ratings or the consolidated gross leverage ratio (as defined in the 2015 Senior Credit Agreement) (whichever yields a lower applicable interest rate margin) at such time. In addition, Ashland was required to pay fees of 0.25% per annum on the daily unused amount of the 2015 revolving credit facility through and including June 30, 2015, and thereafter the fee rate will fluctuate between 0.175% and 0.40% per annum, based upon Ashland's corporate credit ratings or the consolidated gross leverage ratio (whichever yields a lower fee rate).

Total borrowing capacity remaining under the 2015 revolving credit facility was $1,013 million, due to an outstanding balance of $110 million, as well as a reduction of $77 million for letters of credit outstanding at September 30, 2015.

During 2015, Ashland used the proceeds from borrowings under the $1.1 billion term loan facility along with cash on hand (i) to fund the tender offer of the 2016 senior notes, (ii) to pay in full the outstanding loans under the 2013 Senior Credit Facility, (iii) to pay accrued interest, fees and expenses under the 2013 Senior Credit Facility and the 2016 senior notes, (iv) to contribute funds to the U.S. pension plans impacted by the pension plan settlement program discussed in Note M, and (v) to pay fees and expenses incurred in connection with the entry into the 2015 Senior Credit Agreement. As a result of the tender offer and redemption, Ashland recognized a $9 million charge related to early redemption premium payments, which is included in the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income in 2015.

Ashland incurred $10 million of new debt issuance costs in connection with the 2015 Senior Credit Agreement, of which $2 million was recognized immediately within the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income. The remaining $8 million will be amortized over the term of the 2015 Senior Credit Agreement using the effective interest method. Additionally, as a result of the termination of the 2013 Senior Credit Facility and the repayment of the 2016 senior notes, Ashland recognized a $2 million charge for the accelerated amortization of previously capitalized debt issuance costs, which is included in the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income.

3.000% senior notes, 3.875% senior notes, 4.750% senior notes and 6.875% senior notes

During 2013, Ashland completed its issuance of senior unsecured notes (senior notes) with an aggregate principal amount of $2.3 billion. These senior notes were comprised of 3.000% senior notes due 2016 ($600 million), 3.875% senior notes due 2018 ($700 million), 4.750% senior notes due 2022 ($625 million) and 6.875% senior notes due 2043 ($375 million). As discussed above, the 2016 senior notes were tendered and redeemed during 2015. The 2022 notes were issued as additional notes under the existing 2022 notes indenture entered into in August 2012, and have the same terms as the originally issued 2022 notes. The 2043 notes were issued at a $1 million premium, while the new 2022 notes were issued at a $6 million discount. In accordance with U.S. GAAP, the premium and discount are being accreted into the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income over the terms of the respective notes. Ashland paid $32 million in fees and expenses with respect to the issuance of the senior notes during 2013, which is being amortized proportionately for each tranche of the senior notes.

NOTE I – DEBT (continued)

2013 Senior Credit Facility

During 2013, Ashland also entered the 2013 Senior Credit Facility, a five-year senior unsecured revolving credit facility in an aggregate amount of $1.2 billion, which included a $250 million letter of credit sublimit and a $100 million swing line loan sublimit. The 2013 Senior Credit Facility replaced the $1 billion senior secured revolving credit facility under the 2011 Senior Credit Facility. The 2013 Senior Credit Facility was not guaranteed, was unsecured and could be prepaid at any time without premium. Ashland paid $6 million in fees and expenses with respect to the entry into the 2013 Senior Credit Facility, which was being amortized over the five-year period.

At Ashland's option, loans issued under the 2013 Senior Credit Facility beared interest at either LIBOR or an alternate base rate, in each case plus the applicable interest rate margin. The loans' interest rates fluctuated between LIBOR plus 1.50% per annum and LIBOR plus 2.50% per annum (or between the alternate base rate plus 0.50% per annum and the alternate base rate plus 1.50% per annum), based upon Ashland's corporate credit ratings or the consolidated gross leverage ratio (as defined in the 2013 Senior Credit Facility) (whichever yielded a lower applicable interest rate margin) at such time. In addition, Ashland was initially required to pay fees of 0.30% per annum on the daily unused amount of the 2013 Senior Credit Facility through and including March 31, 2013, and thereafter the fee rate fluctuates between 0.25% and 0.50% per annum, based upon Ashland's corporate credit ratings or the consolidated gross leverage ratio.

During 2013, Ashland used the net proceeds from its issuance of the senior notes, along with the initial $85 million borrowing on the 2013 Senior Credit Facility and cash on hand, (i) to pay in full the 2011 Senior Credit Facility, including the $1.41 billion outstanding principal of the term loan A facility and the $1.03 billion outstanding principal of the term loan B facility, (ii) to pay $52 million to terminate the interest rate swaps associated with the term loan A and term loan B facilities, (iii) to pay accrued interest, fees and expenses under the 2011 Senior Credit Facility and (iv) to pay $38 million in fees and expenses with respect to the issuance of the senior notes and entry into the 2013 Senior Credit Facility. The $52 million charge to terminate the interest rate swaps is included in the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income for 2013.

As a result of the repayment and the termination of the 2011 Senior Credit Facility during 2013, Ashland recognized a $47 million charge for the accelerated amortization of previous debt issuance and other costs, which is included in the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income.

9.125% senior notes

During 2012, $572 million of the total principal amount of the $650 million, 9.125% senior notes were redeemed. During 2013, Ashland redeemed the remaining $78 million outstanding principal of the senior notes. Ashland recognized a $3 million charge for debt issuance costs and the original issue discount related to the 9.125% senior notes, as well as a $4 million charge related to an early redemption premium payment, both of which are included in the net interest and other financing expense caption in the Statements of Consolidated Comprehensive Income for 2013.

Accounts receivable securitization

On August 31, 2012, Ashland entered into a $350 million accounts receivable securitization facility pursuant to (i) a Sale Agreement, among Ashland and certain of its direct and indirect subsidiaries (each an Originator and collectively, the Originators) and CVG Capital III LLC, a wholly-owned "bankruptcy remote" special purpose subsidiary of the Originators (CVG) and (ii) a Transfer and Administration Agreement, among CVG, each Originator, Ashland, as Master Servicer, certain Conduit Investors, Uncommitted Investors, Letter of Credit Issuers, Managing Agents, Administrators and Committed Investors, and The Bank of Nova Scotia, as agent for various secured parties (the Agent). The Transfer and Administration Agreement had a term of three years, but was extendable at the discretion of Ashland and the Investors. During 2015, the termination of the commitments under the Transfer and Administration Agreement was extended from August 28, 2015 to December 31, 2015.

Under the Sale Agreement, each Originator will transfer, on an ongoing basis, certain of its accounts receivable, certain related assets and the right to the collections on those accounts receivable to CVG. Under the terms of the Transfer and Administration Agreement, CVG could, from time to time, obtain up to $350 million (in the form of cash or letters of credit for the benefit of Ashland and its subsidiaries) from the Conduit Investors, the Uncommitted Investors and/or the Committed Investors through the sale of an undivided interest in such accounts receivable, related assets and collections. Subsequently during 2014 and 2015, the available funding for qualifying receivables under the accounts receivable securitization facility was reduced from $350 million to $275 million during 2014 and from $275 million to $250 million during 2015 due to the divestitures that occurred during the fiscal years. Ashland accounts for the securitization facility as secured borrowings, and the receivables sold pursuant to the facility are included in the Consolidated Balance Sheets as accounts receivable. Fundings under the Transfer and Administration Agreement will be repaid as accounts receivable are collected, with new fundings being advanced (through daily reinvestments) as new accounts receivable are originated by the Originators and transferred to CVG, with settlement generally occurring monthly. Ashland continues to classify any borrowings under this facility as a short-term debt instrument within the Consolidated Balance Sheets.

Once sold to CVG, the accounts receivable, related assets and rights to collection described above are separate and distinct from each Originator's own assets and are not available to its creditors should such Originator become insolvent. Substantially all of CVG's assets have been pledged to the Agent in support of its obligations under the Transfer and Administration Agreement.

At September 30, 2015 and 2014, the outstanding amount of accounts receivable transferred by Ashland to CVG was $381 million and $493 million, respectively. Ashland had drawn $190 million and $255 million under the facility as of September 30, 2015 and 2014, respectively, in available funding from qualifying receivables. The weighted-average interest rate for this instrument was 1.8% for 2015 and 1.1% for 2014.

Other debt

At September 30, 2015 and 2014, Ashland held other debt totaling $175 million and $184 million, respectively, comprised primarily of the 6.60% and 6.50% notes due 2027 and 2029, respectively, assumed in the Hercules acquisition, other short-term international loans, and a medium-term note.

Net interest and other financing expense (income)

(In millions)	2015	2014	2013
Interest expense (a)	$ 166	$ 163	$ 273
Interest income	(6)	(6)	(4)
Available-for-sale securities income (b)	(3)	—	—
Other financing costs (c)	17	9	13
	$ 174	$ 166	$ 282

(a) Includes $4 million and $50 million of accelerated amortization for debt issuance costs during 2015 and 2013, respectively, and the $52 million charge to terminate the interest rate swaps associated with the term loan A and term loan B facilities during 2013.
(b) Represents investment income related to the restricted investments discussed in Note F.
(c) Includes $9 million related to the early redemption premium payments for the tender and redemption of the 2016 senior notes during 2015 and a $4 million redemption premium payment related to the $78 million principal 9.125% senior notes redeemed during 2013.

The following table details the debt issuance cost and original issue discount amortization included in interest expense during 2015, 2014 and 2013.

(In millions)	2015 (a)	2014	2013 (b)
Normal amortization	$ 14	$ 14	$ 15
Accelerated amortization	4	—	50
Total	$ 18	$ 14	$ 65

(a) Accelerated amortization of $4 million for debt issuance costs resulting from early redemption of the 2016 senior notes and the entrance into the 2015 Senior Credit Agreement.
(b) Accelerated amortization of $47 million and $3 million resulted from the repayment of the 2011 Senior Credit Facility and the early paydown of Ashland's remaining 9.125% senior notes, respectively.

Covenants related to current debt agreements

The 2015 Senior Credit Agreement contains usual and customary representations, warranties and affirmative and negative covenants, including financial covenants for leverage and interest coverage ratios, limitations on liens, additional subsidiary indebtedness, restrictions on subsidiary distributions, investments, mergers, sale of assets and restricted payments and other customary limitations. As of September 30, 2015, Ashland is in compliance with all debt agreement covenant restrictions.

Financial covenants

The maximum consolidated leverage ratios permitted under the 2015 Senior Credit Agreement are as follows: 3.75 through December 31, 2016 and 3.5 from March 31, 2017 and each fiscal quarter thereafter. The 2015 Senior Credit Agreement defines the consolidated leverage ratio as the ratio of consolidated indebtedness minus unrestricted cash and cash equivalents to consolidated EBITDA (Covenant Adjusted EBITDA) for any measurement period. In general, the 2015 Senior Credit Agreement defines Covenant Adjusted EBITDA as net income plus consolidated interest charges, taxes, depreciation and amortization expense, fees and expenses related to capital market transactions, restructuring and integration charges, noncash stock and equity compensation expense, and any other nonrecurring expenses or losses that do not represent a cash item in such period or any future period; less any noncash gains or other items increasing net income. The computation of Covenant Adjusted EBITDA differs from the

calculation of EBITDA and Adjusted EBITDA, which have been reconciled on page M-7. In general, consolidated indebtedness includes debt plus all purchase money indebtedness, banker's acceptances and bank guaranties, deferred purchase price of property or services, attributable indebtedness and guarantees.

The minimum required consolidated interest coverage ratio under the 2015 Senior Credit Agreement during its entire duration is 3.0. The 2015 Senior Credit Agreement defines the consolidated interest coverage ratio as the ratio of Covenant Adjusted EBITDA to consolidated interest charges for any measurement period.

At September 30, 2015, Ashland's calculation of the consolidated leverage ratio was 2.6, which is below the maximum consolidated leverage ratio permitted under the 2015 Senior Credit Agreement of 3.75. At September 30, 2015, Ashland's calculation of the interest coverage ratio was 6.4, which exceeds the minimum required consolidated ratio of 3.0.

NOTE J – OTHER NONCURRENT ASSETS AND LIABILITIES

The following table provides the components of other noncurrent assets in the Consolidated Balance Sheets as of September 30.

(In millions)	2015	2014
Deferred compensation investments	$ 180	$ 184
Debt issuance costs	16	18
Note receivables	36	44
Manufacturing catalyst supplies	37	24
Environmental insurance receivables	16	24
Land use rights	22	23
Defined benefit plan assets	29	22
Life insurance policies	18	18
Tax receivables	7	17
Customer incentive	16	16
Debt defeasance assets	6	15
Other	93	74
	$ 476	$ 479

The following table provides the components of other noncurrent liabilities in the Consolidated Balance Sheets as of September 30.

(In millions)	2015	2014
Environmental remediation reserves	$ 139	$ 158
Accrued tax liabilities (including sales and franchise)	103	74
Deferred compensation	66	72
Reserves related to workers compensation and general liability	24	50
Other	73	106
	$ 405	$ 460

NOTE K – LEASE COMMITMENTS

Ashland and its subsidiaries are lessees of office buildings, retail outlets, transportation equipment, warehouses and storage facilities, other equipment, facilities and properties under leasing agreements that expire at various dates. Capitalized lease obligations are not significant and are included in long-term debt while capital lease assets are included in property, plant and equipment. Future minimum rental payments at September 30, 2015 were $40 million in 2016, $31 million in 2017, $24 million in 2018, $19 million in 2019, $15 million in 2020 and $61 million in 2021 and later years. Rental expense under operating leases for continuing operations was as follows:

NOTE K – LEASE COMMITMENTS (continued)

(In millions)	2015	2014	2013 (a)
Minimum rentals (including rentals under short-term leases)	$ 57	$ 69	$ 57
Contingent rentals	4	7	6
Sublease rental income	(2)	(2)	(2)
	$ 59	$ 74	$ 61

(a) The table above excludes $13 million of lease commitments during 2013 that were related to the Water Technologies business that have been reclassified to discontinued operations due to its sale in July 2014.

NOTE L – INCOME TAXES

A summary of the provision for income taxes related to continuing operations follows.

(In millions)	2015	2014	2013
Current			
Federal	$ (32)	$ 34	$ 7
State	1	10	(6)
Foreign	66	62	42
	35	106	43
Deferred	(57)	(294)	153
Income tax expense (benefit)	$ (22)	$ (188)	$ 196

Deferred income taxes are provided for income and expense items recognized in different years for tax and financial reporting purposes. As of September 30, 2015, management intends to indefinitely reinvest approximately $1.6 billion of foreign earnings. Because these earnings are considered indefinitely reinvested, no U.S. tax provision has been accrued related to the repatriation of these earnings, and it is not practicable to estimate the amount of U.S. tax that might be payable if these earnings were ever to be remitted.

Foreign net operating loss carryforwards primarily relate to certain European and Asian Pacific operations and generally may be carried forward. U.S. state net operating loss carryforwards relate to operational losses within certain states and generally may be carried forward. Temporary differences that give rise to significant deferred tax assets and liabilities as of September 30 are presented in the following table.

(In millions)	2015	2014
Deferred tax assets		
Foreign net operating loss carryforwards (a)	$ 81	$ 84
Employee benefit obligations	392	544
Environmental, self-insurance and litigation reserves (net of receivables)	218	172
State net operating loss carryforwards (b)	73	58
Compensation accruals	88	91
Credit carryforwards (c)	89	25
Other items	26	65
Valuation allowances (d)	(107)	(148)
Total deferred tax assets	860	891
Deferred tax liabilities		
Goodwill and other intangibles (e)	371	409
Property, plant and equipment	351	416
Unremitted earnings	11	19
Total deferred tax liabilities	733	844
Net deferred tax asset (liability)	$ 127	$ 47

(a) Gross net operating loss carryforwards will expire in future years as follows: $2 million in 2016, $13 million in 2017 and the remaining balance in other future years.
(b) Gross net operating loss carryforwards include offset for uncertain tax positions of and will expire in future years as follows: $20 million in 2016, $38 million in 2017 and the remaining balance in other future years.
(c) Credit carryforwards include offset for uncertain tax positions and consist primarily of foreign tax credits of $67 million expiring in future years beyond 2017 and alternative minimum tax credits of $12 million with no expiration date.
(d) Valuation allowances primarily relate to certain state and foreign net operating loss carryforwards.
(e) The total gross amount of goodwill as of September 30, 2015 expected to be deductible for tax purposes is $38 million.

The U.S. and foreign components of income from continuing operations before income taxes and a reconciliation of the statutory federal income tax with the provision for income taxes follow. The foreign components of income from continuing operations disclosed in the following table exclude any allocations of certain corporate expenses incurred in the U.S.

(In millions)	2015	2014	2013
Income (loss) from continuing operations before income taxes			
United States (a), (b)	$ (158)	$ (364)	$ 466
Foreign (b)	327	248	283
Total income (loss) from continuing operations before income taxes	$ 169	$ (116)	$ 749
Income taxes computed at U.S. statutory rate (35%)	$ 59	$ (40)	$ 262
Increase (decrease) in amount computed resulting from			
Net gain on divestitures (c)	11	37	—
Uncertain tax positions	23	33	11
Valuation allowance charges (d)	(29)	14	(12)
Claim for research and development credits (e)	(7)	(2)	(14)
State taxes (f)	(8)	(16)	23
Net impact of foreign results (g)	(73)	(214)	(74)
Other items	2	—	—
Income tax expense (benefit)	$ (22)	$ (188)	$ 196

(a) A significant component of the fluctuations within this caption relates to the annual remeasurements of the U.S. pension and other postretirement plans.
(b) Prior year amounts for income (loss) from continuing operations before income taxes for the United States and Foreign line items have been revised to reflect a change in the classification of the elimination of foreign intercompany dividends. There was no impact on the total of income (loss) from continuing operations before income taxes or on the computation of income tax expense (benefit) for the years ended September 30, 2014 and 2013 and therefore Ashland does not believe that this revision is material to the previously filed financial information.
(c) 2015 includes adjustments related to the sale of Valvoline Venezuela JV, Elastomers and the Biocides divestitures of $5 million, $4 million and $2 million respectively. 2014 tax adjustments associated with the Water Technologies business and ASK divestitures are a $39 million charge and $2 million gain respectively.
(d) Related to foreign and state deferred tax asset valuation allowances/(releases).
(e) 2015 and 2013 include a benefit related to credits signed into law on a retroactive basis.
(f) 2014 and 2013 include expense of $5 million and $7 million, respectively, recorded for deferred tax adjustments, primarily attributable to state rate changes.
(g) 2014 includes a $168 million tax benefit related to the reversal of deferred tax liabilities for outside basis differences and other related matters and a $14 million expense recorded for a rate change in a foreign jurisdiction. 2013 includes a $17 million benefit recorded for a rate change in a foreign jurisdiction.

The fiscal 2015 effective tax rate was impacted by net favorable items predominantly due to certain valuation allowance releases related to state deferred tax assets. These favorable adjustments were partially offset by an accrual for an unrecognized tax benefit and tax related to certain global restructuring steps.

Income tax benefit for 2014 included a $168 million tax benefit related to the reversal of deferred tax liabilities for outside basis differences and other related matters, a charge of $39 million for taxes associated with the sale of shares of subsidiaries included in the sale of the Water Technologies business, net charges of $32 million for uncertain tax positions and related matters, a charge of $14 million for a foreign income tax rate change and other net discrete item charges of $7 million primarily related to changes in valuation allowances.

Income tax expense for 2013 included a zero benefit recorded on the MAP Transaction charge of $14 million and a net benefit of $16 million primarily attributable to a foreign income tax rate change.

Unrecognized tax benefits

U.S. GAAP prescribes a recognition threshold and measurement attribute for the accounting and financial statement disclosure of tax positions taken or expected to be taken in a tax return. The evaluation of a tax position is a two-step process. The first step requires Ashland to determine whether it is more likely than not that a tax position will be sustained upon examination based on the technical merits of the position. The second step requires Ashland to recognize in the financial statements each tax position that meets the more likely than not criteria, measured at the amount of benefit that has a greater than 50% likelihood of being realized. Ashland had $144 million and $155 million of unrecognized tax benefits, of which $16 million and $32 million relate to discontinued operations at September 30, 2015 and 2014, respectively. As of September 30, 2015, the total amount of unrecognized tax benefits that, if recognized, would affect the tax rate for continuing and discontinued operations was $127 million. The remaining unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits would not have an impact on the effective tax rate.

Ashland recognizes interest and penalties related to uncertain tax positions as a component of income tax expense (benefit) in the Statements of Consolidated Comprehensive Income. Such interest and penalties totaled a $1 million expense in 2015, $2

million benefit in 2014 and $5 million benefit in 2013. Ashland had $18 million and $19 million in interest and penalties related to unrecognized tax benefits accrued as of September 30, 2015 and 2014, respectively.

During the year ended September 30, 2015 and 2014, respectively, changes in unrecognized tax benefits were as follows:

(In millions)	
Balance at September 30, 2013	$ 133
Increases related to positions taken on items from prior years	29
Decreases related to positions taken on items from prior years	(13)
Increases related to positions taken in the current year	31
Lapse of statute of limitations	(13)
Disposition of Water Technologies	(12)
Balance at September 30, 2014	155
Increases related to positions taken on items from prior years	10
Decreases related to positions taken on items from prior years	(15)
Increases related to positions taken in the current year	24
Lapse of statute of limitations	(6)
Settlement of uncertain tax positions with tax authorities	(24)
Balance at September 30, 2015	$ 144

From a combination of statute expirations and audit settlements in the next twelve months, Ashland expects a decrease in the amount of accrual for uncertain tax positions of up to $3 million for continuing operations and zero for discontinued operations. For the remaining balance as of September 30, 2015, it is reasonably possible that there could be material changes to the amount of uncertain tax positions due to activities of the taxing authorities, settlement of audit issues, reassessment of existing uncertain tax positions, or the expiration of applicable statute of limitations; however, Ashland is not able to estimate the impact of these items at this time.

Ashland or one of its subsidiaries files income tax returns in the U.S. federal jurisdiction and various state and foreign jurisdictions. Foreign taxing jurisdictions significant to Ashland include Australia, Canada, Spain, Switzerland, Brazil, Mexico, China, Germany and the Netherlands. Ashland is subject to U.S. federal income tax examinations by tax authorities for periods after September 30, 2009 and U.S. state income tax examinations by tax authorities for periods after September 30, 2005. With respect to countries outside of the United States, with certain exceptions, Ashland's foreign subsidiaries are subject to income tax audits for years after 2004.

NOTE M – EMPLOYEE BENEFIT PLANS

Pension plans

Ashland and its subsidiaries sponsor contributory and noncontributory qualified defined benefit pension plans that cover certain employees in the United States and in a number of other countries. In addition, Ashland has non-qualified unfunded pension plans which provide supplemental defined benefits to those employees whose benefits under the qualified pension plans are limited by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code. Ashland funds the costs of the non-qualified plans as the benefits are paid. Pension obligations for applicable employees of non-U.S. consolidated subsidiaries are provided for in accordance with local practices and regulations of the respective countries. Benefits for those eligible for Ashland's U.S. pension plans generally are based on employees' years of service and compensation during the years immediately preceding their retirement.

The majority of Ashland's U.S. pension plans have been closed to new participants since January 1, 2011. In addition, most foreign pension plans are closed to new participants while those that remain open relate to areas where jurisdictions require plans to operate within the applicable country.

Pension plan settlement program

During 2015, Ashland informed approximately 20,000 former employees, who were included in the approximately 53,000 participants within the primary U.S. pension plans, that Ashland was offering these participants the option of receiving a lump sum payment on their vested retirement benefit or a reduced annuity now, in lieu of receiving monthly annuity payments deferred until retirement eligibility or when the participant may choose to initiate payment. During August 2015, approximately 12,000 participants elected to participate in the settlement program which resulted in approximately $475 million in settlement payments

made from the affected pension plans during September 2015. Settlement payments were funded with pension plan assets, which included the $500 million contribution made during the third quarter of fiscal 2015. Additionally, as a result of this settlement program, Ashland recognized a $3 million settlement gain during 2015, of which $1 million and $2 million was recognized in the cost of sales and selling, general and administrative expense captions, respectively, within the Statements of Consolidated Comprehensive Income.

Pension plans divested

As a result of the sale of the Water Technologies business on July 31, 2014, certain non-U.S. pension plans, with a net benefit obligation of $70 million were fully transferred.

Other postretirement benefit plans

Ashland and its subsidiaries sponsor health care and life insurance plans for eligible employees in the U.S. and Canada who retire or are disabled. Ashland's retiree life insurance plans are noncontributory, while Ashland shares the costs of providing health care coverage with its retired employees through premiums, deductibles and coinsurance provisions. Ashland funds its share of the costs of the postretirement benefit plans as the benefits are paid. Employees hired after June 30, 2003, and participating in the Ashland plans, will have access to any retiree health care coverage that may be provided, but will have no Ashland company funds available to help pay for such coverage.

Since January 1, 2004, Ashland's legacy plans have limited their annual per capita costs to an amount equivalent to base year per capita costs, plus annual increases of up to 1.5% per year for costs incurred. As a result, health care cost trend rates have no significant effect on the amounts reported for the health care plans. Premiums for retiree health care coverage are equivalent to the excess of the estimated per capita costs over the amounts borne by Ashland.

For certain other plans that have been acquired, the assumed postretirement health care plans include a limit on Ashland's share of costs for recent and future retirees. The assumed pre-65 health care cost trend rate as of September 30, 2015 was 8.3% and continues to be reduced to 4.50% in 2037 and thereafter. The assumptions used to project the liability anticipate future cost-sharing changes to the written plans that are consistent with the increase in health care cost. Employees hired after December 31, 2002 will have access to any retiree health care coverage that may be provided, but will have no Ashland company funds available to help pay for such coverage.

In May 2010, Ashland implemented changes for all plans, effective January 1, 2011, eliminating post-65 benefit coverage for those eligible participants retiring on or after January 1, 2016. In September 2011, Ashland adopted a plan amendment for the legacy Ashland plans to change the current post-65 Ashland Medical plan to Medicare Advantage plan. This change was effective January 1, 2012, at which time Ashland no longer applied for the Medicare Part D subsidy. In September 2012, Ashland further reduced the employer subsidy for the post-65 Ashland legacy Medicare Advantage Plan to account for the impact of certain changes to the prescription drug program adopted as part of the September 2011 plan amendment.

Components of net periodic benefit costs (income)

During the year ended September 30, 2015, Ashland was required to remeasure a non-U.S. pension plan due to the exit of Water Technologies' employees from the plan. As a result of the remeasurement, Ashland recognized a curtailment gain of $7 million and actuarial loss of $11 million during 2015. Of these amounts, all of the curtailment gain and $2 million of the actuarial loss were attributable to the Water Technologies business and therefore included in the discontinued operations caption of the Statements of Consolidated Comprehensive Income during 2015.

During the year ended September 30, 2014, Ashland settled two non-U.S. pension plans, which required the plans to be remeasured. These remeasurements resulted in Ashland recognizing a settlement loss of $38 million and actuarial loss of $17 million. Of these amounts, $6 million of the settlement loss and $3 million of the actuarial loss were attributable to the Water Technologies business and therefore included in the discontinued operations caption of the Statements of Consolidated Comprehensive Income during 2014.

Due to the global restructuring plan initiated in January 2014, Ashland was required to remeasure certain pension and other postretirement plan obligations, which included updating assumptions related to these plans such as the discount rate, asset values and demographic data that were last updated at Ashland's fiscal year end. As a result of the remeasurements, Ashland recognized a curtailment loss of $6 million and actuarial loss of $83 million during the year ended September 30, 2014. Of these amounts, $14 million of the actuarial loss was attributable to the Water Technologies business and included in the discontinued operations caption of the Statements of Consolidated Comprehensive Income during 2014.

As a result of the completion of the sale of Water Technologies on July 31, 2014, Ashland was required to remeasure certain pension and other postretirement plan obligations. As a result of the remeasurements, Ashland recognized a curtailment gain of $31 million and actuarial loss of $140 million during the year ended September 30, 2014. Of these amounts, all of the curtailment gain and $27 million of the actuarial loss were attributable to the Water Technologies business and included in the discontinued

operations caption of the Statements of Consolidated Comprehensive Income during 2014. In addition, during 2013, $81 million of the actuarial gain was attributable to the Water Technologies business and included within the discontinued operations caption of the Statements of Consolidated Comprehensive Income.

For segment reporting purposes, service cost for continuing operations is proportionately allocated to each reportable segment, excluding the Unallocated and other segment, while all other costs for continuing operations are recorded within the Unallocated and other segment. A portion of the other components of pension and other postretirement benefit costs (i.e., interest cost, expected return on assets, and amortization of prior service credit) related to Water Technologies has been reclassified to discontinued operations in the Statements of Consolidated Comprehensive Income. For the years ended September 30, 2014 and 2013, income of $7 million and $11 million, respectively, was classified within discontinued operations.

The following table summarizes the components of pension and other postretirement benefit costs for both continued and discontinued operations and the assumptions used to determine net periodic benefit costs (income) for the plans.

	Pension benefits			Other postretirement benefits		
(In millions)	2015	2014	2013	2015	2014	2013
Net periodic benefit costs (income)						
Service cost	$ 26	$ 38	$ 43	$ 1	$ 2	$ 2
Interest cost	175	190	175	8	9	7
Curtailment, settlement and other	(11)	31	—	—	(20)	—
Expected return on plan assets	(216)	(237)	(238)	—	—	—
Amortization of prior service credit (a)	(4)	(2)	(2)	(17)	(21)	(21)
Actuarial loss (gain)	260	431	(472)	1	15	(26)
	$ 230	$ 451	$ (494)	$ (7)	$ (15)	$ (38)
Weighted-average plan assumptions (b)						
Discount rate	4.18%	4.68%	3.70%	3.85%	4.28%	3.23%
Rate of compensation increase	3.18%	3.59%	3.66%	—	—	—
Expected long-term rate of return on plan assets	7.27%	7.67%	7.26%	—	—	—

(a) Changes to the post-65 Ashland Medical plan resulted in negative plan amendments that are being amortized within the other postretirement benefits caption.
(b) The plan assumptions discussed are a blended weighted-average rate for Ashland's U.S. and non-U.S. plans. The U.S. pension plan represented approximately 90% of the projected benefit obligation at September 30, 2015. Other postretirement benefit plans consist of U.S. and Canada, with the U.S. plan representing approximately 93% of the accumulated postretirement benefit obligation at September 30, 2015. Non-U.S. plans use assumptions generally consistent with those of U.S. plans.

The following table shows other changes in prior service credit recognized in accumulated other comprehensive income.

	Pension		Postretirement	
(In millions)	2015	2014	2015	2014
Prior service cost (credit)	$ 2	$ (6)	$ —	$ —
Curtailment, settlement and other	3	3	—	10
Amortization of prior service credit	4	2	17	21
Total	$ 9	$ (1)	$ 17	$ 31
Total recognized in net periodic benefit cost (income) and accumulated other comprehensive income	$ 239	$ 450	$ 10	$ 16

The following table shows the amount of prior service credit in accumulated other comprehensive income at September 30, 2015 that is expected to be recognized as a component of net periodic benefit cost (income) during the next fiscal year.

(In millions)	Pension benefits	Other postretirement benefits
Prior service credit	$ (2)	$ (16)

At September 30, 2015 and 2014, the amounts recognized in accumulated other comprehensive income are shown in the following table.

	Pension		Postretirement	
(In millions)	2015	2014	2015	2014
Prior service credit	$ (12)	$ (21)	$ (45)	$ (62)

Obligations and funded status

Actuarial valuations are performed for the pension and other postretirement benefit plans to determine Ashland's obligation for each plan. In accordance with U.S. GAAP, Ashland recognizes the unfunded status of the plans as a liability in the Consolidated Balance Sheets. Summaries of the change in benefit obligations, plan assets, funded status of the plans, amounts recognized in the balance sheet, and assumptions used to determine the benefit obligations for 2015 and 2014 follow.

(In millions)	Pension plans 2015	Pension plans 2014	Other postretirement benefit plans 2015	Other postretirement benefit plans 2014
Change in benefit obligations				
Benefit obligations at October 1	$ 4,326	$ 4,307	$ 210	$ 217
Service cost	26	38	1	2
Interest cost	175	190	8	9
Participant contributions	1	2	15	12
Benefits paid	(217)	(245)	(33)	(34)
Actuarial loss	59	503	1	15
Plan amendment	2	(6)	—	—
Foreign currency exchange rate changes	(40)	(15)	(3)	(1)
Other	14	4	—	—
Divestiture	—	(127)	—	—
Curtailment and settlement	(527)	(325)	—	(10)
Benefit obligations at September 30	$ 3,819	$ 4,326	$ 199	$ 210
Change in plan assets				
Value of plan assets at October 1	$ 3,075	$ 3,381	$ —	$ —
Actual return on plan assets	15	309	—	—
Employer contributions	610	43	18	22
Participant contributions	1	2	15	12
Benefits paid	(217)	(245)	(33)	(34)
Foreign currency exchange rate changes	(28)	(5)	—	—
Settlement	(519)	(359)	—	—
Divestiture	—	(57)	—	—
Other	14	6	—	—
Value of plan assets at September 30	$ 2,951	$ 3,075	$ —	$ —
Unfunded status of the plans	$ (868)	$ (1,251)	$ (199)	$ (210)
Amounts recognized in the balance sheet				
Noncurrent benefit assets	$ 29	$ 22	$ —	$ —
Current benefit liabilities	(19)	(15)	(17)	(19)
Noncurrent benefit liabilities	(878)	(1,258)	(182)	(191)
Net amount recognized	$ (868)	$ (1,251)	$ (199)	$ (210)
Weighted-average plan assumptions				
Discount rate	4.21%	4.18%	3.93%	3.85%
Rate of compensation increase	3.01%	3.18%	—	—

The accumulated benefit obligation for all pension plans was $3,750 million at September 30, 2015 and $4,261 million at September 30, 2014. Information for pension plans with an accumulated benefit obligation in excess of plan assets follows:

	2015			2014		
(In millions)	Qualified plans (a)	Non-qualified plans	Total	Qualified plans (a)	Non-qualified plans	Total
Projected benefit obligation	$ 3,446	$ 162	$ 3,608	$ 3,930	$ 172	$ 4,102
Accumulated benefit obligation	3,390	156	3,546	3,880	165	4,045
Fair value of plan assets	2,712	—	2,712	2,832	—	2,832

(a) Includes qualified U.S. and non-U.S. pension plans.

Plan assets

The expected long-term rate of return on U.S. pension plan assets was 7.65% and 8% for 2015 and 2014, respectively. The basis for determining the expected long-term rate of return is a combination of future return assumptions for various asset classes in Ashland's investment portfolio, historical analysis of previous returns, market indices and a projection of inflation.

The following table summarizes the various investment categories that the pension plan assets are invested in and the applicable fair value hierarchy that the financial instruments are classified within these investment categories as of September 30, 2015. For additional information and a detailed description of each level within the fair value hierarchy, see Note F.

(In millions)	Total fair value	Quoted prices in active markets for identical assets Level 1	Significant other observable inputs Level 2	Significant unobservable inputs Level 3
Cash and cash equivalents	$ 91	$ 91	$ —	$ —
U.S. government securities	130	4	126	—
Other government securities	163	1	162	—
Corporate debt instruments	1,398	1,036	362	—
Corporate stocks	289	146	143	—
Insurance contracts	10	—	10	—
Private equity and hedge funds	842	—	—	842
Other investments	28	—	—	28
Total assets at fair value	$ 2,951	$ 1,278	$ 803	$ 870

The following table summarizes the various investment categories that the pension plan assets are invested in and the applicable fair value hierarchy that the financial instruments are classified within these investment categories as of September 30, 2014.

(In millions)	Total fair value	Quoted prices in active markets for identical assets Level 1	Significant other observable inputs Level 2	Significant unobservable inputs Level 3
Cash and cash equivalents	$ 102	$ 102	$ —	$ —
U.S. government securities	180	7	173	—
Other government securities	165	—	165	—
Corporate debt instruments	1,172	788	384	—
Corporate stocks	326	158	168	—
Insurance contracts	12	—	12	—
Private equity and hedge funds	1,085	—	—	1,085
Other investments	33	—	—	33
Total assets at fair value	$ 3,075	$ 1,055	$ 902	$ 1,118

Ashland's pension plan holds a variety of investments designed to diversify risk. Investments classified as a Level 1 fair value measure principally represent marketable securities priced in active markets. Cash and cash equivalents and public equity and debt securities are well diversified and invested in U.S. and international small-to-large companies across various asset managers and styles. Investments classified as a Level 2 fair value measure principally represents fixed-income securities in U.S. treasuries and agencies and other investment grade corporate bonds and debt obligations.

Ashland's pension plans also hold Level 3 investments primarily within hedge funds and private equity funds with hedge funds accounting for nearly all of the Level 3 investments. Ashland's investments in these funds are primarily valued using the net asset value per share of underlying investments as determined by the respective individual fund administrators on a daily, weekly or monthly basis, depending on the fund. Such valuations are reviewed by the portfolio managers who determine the estimated value of the collective funds based on these inputs. The following table provides a reconciliation of the beginning and ending balances for these Level 3 assets.

(In millions)	Total Level 3 assets	Private equity and hedge funds	Other investments
Balance as of September 30, 2013	$ 1,228	$ 1,190	$ 38
Purchases	71	71	—
Sales	(258)	(258)	—
Actual return on plan assets			
Relating to assets held at September 30, 2014	67	72	(5)
Relating to assets sold during 2014	10	10	—
Balance as of September 30, 2014	1,118	1,085	33
Purchases	1	1	—
Sales	(252)	(252)	—
Actual return on plan assets			
Relating to assets held at September 30, 2015	3	8	(5)
Relating to assets sold during 2015	—	—	—
Balance as of September 30, 2015	$ 870	$ 842	$ 28

Investments and Strategy

In developing an investment strategy for its defined benefit plans, Ashland has considered the following factors: the nature of the plans' liabilities, the allocation of liabilities between active, deferred and retired members, the funded status of the plans, the applicable investment horizon, the respective size of the plans and historical and expected capital market returns. Ashland's U.S. pension plan assets are managed by outside investment managers, which are monitored against investment return benchmarks and Ashland's established investment strategy. Investment managers are selected based on an analysis of, among other things, their investment process, historical investment results, frequency of management turnover, cost structure and assets under management. Assets are periodically reallocated between investment managers to maintain an appropriate asset mix and diversification of investments and to optimize returns.

The current target asset allocation for the U.S. plan is 51% fixed securities and 49% equity securities. Fixed income securities primarily include long duration high grade corporate debt obligations. Risk assets include both traditional equity as well as a mix of non-traditional assets such as hedge funds and private equity. Investment managers may employ a limited use of derivatives to gain efficient exposure to markets.

Ashland's investment strategy and management practices relative to plan assets of non-U.S. plans generally are consistent with those for U.S. plans, except in those countries where investment of plan assets is dictated by applicable regulations. The weighted-average asset allocations for Ashland's U.S. and non-U.S. plans at September 30, 2015 and 2014 by asset category follow.

(In millions)	Target	Actual at September 30 2015	2014
Plan assets allocation			
Equity securities	15 - 60%	42%	51%
Debt securities	40 - 85%	56%	47%
Other	0 - 20%	2%	2%
		100%	100%

Cash flows

U.S. pension legislation and future funding requirements

Ashland's U.S. qualified pension plans funding requirements through fiscal 2017 are calculated in accordance with the regulations set forth in the Moving Ahead for Progress in the 21st Century Act (MAP-21), which provides temporary relief for employers who sponsor defined benefit pension plans related to funding contributions under the Employee Retirement Income Security Act of 1974. Specifically, MAP-21 allows for the use of a 25-year average interest rate within an upper and lower range for purposes of determining minimum funding obligations instead of an average interest rate for the two most recent years, as was previously required.

During fiscal 2015 and 2014, Ashland contributed $596 million and $22 million, respectively, to its U.S. pension plans and $14 million and $21 million, respectively, to its non-U.S. pension plans. The 2015 contributions included $500 million to the U.S. pension plans impacted by the pension plan settlement program discussed previously. As a result of the $500 million discretionary contribution, Ashland's funding requirements to U.S. qualified pension plans have been eliminated for fiscal year 2016. Ashland expects to contribute approximately $15 million to its non-qualified U.S. pension plans and $15 million to its non-U.S. pension plans during 2016.

The following benefit payments, which reflect future service expectations, are projected to be paid in each of the next five years and in aggregate for five years thereafter.

(In millions)	Pension benefits	Other postretirement benefits
2016	$ 240	$ 18
2017	235	17
2018	235	17
2019	236	17
2020	237	16
2021 - 2025	1,189	71

Other plans

Ashland sponsors savings plans to assist eligible employees in providing for retirement or other future needs. Under such plans, company contributions amounted to $38 million in 2015, $31 million in 2014 and $43 million in 2013. Ashland also sponsors various other benefit plans, some of which are required by different countries. The total noncurrent liabilities associated with these plans were $16 million and $19 million as of September 30, 2015 and 2014, respectively.

NOTE N – LITIGATION, CLAIMS AND CONTINGENCIES

Asbestos litigation

Ashland and Hercules have liabilities from claims alleging personal injury caused by exposure to asbestos. To assist in developing and annually updating independent reserve estimates for future asbestos claims and related costs given various assumptions, Ashland retained Hamilton, Rabinovitz & Associates, Inc. (HR&A). The methodology used by HR&A to project future asbestos costs is based largely on recent experience, including claim-filing and settlement rates, disease mix, enacted legislation, open claims and litigation defense. The claim experience of Ashland and Hercules are separately compared to the results of previously conducted third party epidemiological studies estimating the number of people likely to develop asbestos-related diseases. Those studies were undertaken in connection with national analyses of the population expected to have been

exposed to asbestos. Using that information, HR&A estimates a range of the number of future claims that may be filed, as well as the related costs that may be incurred in resolving those claims. Changes in asbestos-related liabilities and receivables are recorded on an after-tax basis within the discontinued operations caption in the Statements of Consolidated Comprehensive Income.

Ashland asbestos-related litigation

The claims alleging personal injury caused by exposure to asbestos asserted against Ashland result primarily from indemnification obligations undertaken in 1990 in connection with the sale of Riley, a former subsidiary. The amount and timing of settlements and number of open claims can fluctuate from period to period. A summary of Ashland asbestos claims activity, excluding Hercules claims, follows.

(In thousands)	2015	2014	2013
Open claims - beginning of year	65	65	66
New claims filed	2	2	2
Claims settled	—	(1)	(1)
Claims dismissed	(7)	(1)	(2)
Open claims - end of year	60	65	65

Ashland asbestos-related liability

From the range of estimates, Ashland records the amount it believes to be the best estimate of future payments for litigation defense and claim settlement costs, which generally approximates the mid-point of the estimated range of exposure from model results. Ashland reviews this estimate and related assumptions quarterly and annually updates the results of a non-inflated, non-discounted approximate 50-year model developed with the assistance of HR&A.

During the most recent update, completed during 2015, it was determined that the liability for Ashland asbestos claims did not need to be adjusted. Total reserves for asbestos claims were $409 million at September 30, 2015 compared to $438 million at September 30, 2014.

A progression of activity in the asbestos reserve is presented in the following table.

(In millions)	2015	2014	2013
Asbestos reserve - beginning of year	$ 438	$ 463	$ 522
Reserve adjustment	—	4	(28)
Amounts paid	(29)	(29)	(31)
Asbestos reserve - end of year	$ 409	$ 438	$ 463

Ashland asbestos-related receivables

Ashland has insurance coverage for certain litigation defense and claim settlement costs incurred in connection with its asbestos claims, and coverage-in-place agreements exist with the insurance companies that provide substantially all of the coverage that will be accessed.

For the Ashland asbestos-related obligations, Ashland has estimated the value of probable insurance recoveries associated with its asbestos reserve based on management's interpretations and estimates surrounding the available or applicable insurance coverage, including an assumption that all solvent insurance carriers remain solvent. Substantially all of the estimated receivables from insurance companies are expected to be due from domestic insurers. Approximately 45% of the receivable is from insurance companies rated by A.M. Best, all of which have a credit rating of A- or higher as of September 30, 2015.

In October 2012, Ashland and Hercules initiated various arbitration proceedings against Underwriters at Lloyd's, certain London companies and/or Chartis (AIG) member companies seeking to enforce these insurers' contractual obligations to provide indemnity for asbestos liabilities and defense costs under existing coverage-in-place agreements. In addition, Ashland and Hercules initiated a lawsuit in Kentucky state court against certain Berkshire Hathaway entities (National Indemnity Company and Resolute Management, Inc.) on grounds that these Berkshire Hathaway entities had wrongfully interfered with Underwriters' and Chartis' performance of their respective contractual obligations to provide asbestos coverage by directing the insurers to reduce and delay certain claim payments.

On January 13, 2015, Ashland and Hercules entered into a comprehensive settlement agreement related to certain insurance coverage for asbestos bodily injury claims with Underwriters at Lloyd's, certain London companies and Chartis (AIG) member companies, along with National Indemnity Company and Resolute Management, Inc., under which Ashland and Hercules received a total of $398 million. In exchange, all claims were released against these entities for past, present and future coverage obligations arising out of the asbestos coverage-in-place agreements that were the subject of the pending arbitration proceedings. In addition, as part of this settlement, Ashland and Hercules released all claims against National Indemnity Company and Resolute Management, Inc. in the Kentucky state court action. As a result, the arbitration proceedings and the Kentucky state court action have been terminated.

As a result of this settlement, Ashland recorded an after-tax gain of $120 million within the discontinued operations caption of the Statements of Consolidated Comprehensive Income during 2015. The Ashland insurance receivable balance was also reduced as a result of this settlement by $227 million within the Consolidated Balance Sheets.

In addition, Ashland placed $335 million of the settlement funds received into a renewable annual trust restricted for the purpose of paying for ongoing and future litigation defense and claim settlement costs incurred in conjunction with asbestos claims.

At September 30, 2015, Ashland's receivable for recoveries of litigation defense and claim settlement costs from insurers amounted to $150 million (excluding the Hercules receivable for asbestos claims), of which $12 million relates to costs previously paid. Receivables from insurers amounted to $402 million at September 30, 2014. During 2015, the annual update of the model used for purposes of valuing the asbestos reserve and its impact on valuation of future recoveries from insurers, was completed. This model update resulted in a $3 million decrease in the receivable for probable insurance recoveries.

A progression of activity in the Ashland insurance receivable is presented in the following table.

(In millions)	2015	2014	2013
Insurance receivable - beginning of year	$ 402	$ 408	$ 423
Receivable adjustment	(3)	22	(3)
Insurance settlement	(227)	—	—
Amounts collected	(22)	(28)	(12)
Insurance receivable - end of year	$ 150	$ 402	$ 408

Hercules asbestos-related litigation

Hercules has liabilities from claims alleging personal injury caused by exposure to asbestos. Such claims typically arise from alleged exposure to asbestos fibers from resin encapsulated pipe and tank products which were sold by one of Hercules' former subsidiaries to a limited industrial market. The amount and timing of settlements and number of open claims can fluctuate from period to period. A summary of Hercules' asbestos claims activity follows.

(In thousands)	2015	2014	2013
Open claims - beginning of year	21	21	21
New claims filed	1	1	1
Claims dismissed	(2)	(1)	(1)
Open claims - end of year	20	21	21

Hercules asbestos-related liability

From the range of estimates, Ashland records the amount it believes to be the best estimate of future payments for litigation defense and claim settlement costs, which generally approximates the mid-point of the estimated range of exposure from model results. Ashland reviews this estimate and related assumptions quarterly and annually updates the results of a non-inflated, non-discounted approximate 50-year model developed with the assistance of HR&A. As a result of the most recent annual update of this estimate, completed during 2015, it was determined that the liability for Hercules asbestos-related claims should be increased by $4 million. Total reserves for asbestos claims were $311 million at September 30, 2015 compared to $329 million at September 30, 2014.

A progression of activity in the asbestos reserve is presented in the following table.

(In millions)	2015	2014	2013
Asbestos reserve - beginning of year	$ 329	$ 342	$ 320
Reserve adjustments	4	10	46
Amounts paid	(22)	(23)	(24)
Asbestos reserve - end of year	$ 311	$ 329	$ 342

Hercules asbestos-related receivables

For the Hercules asbestos-related obligations, certain reimbursement obligations pursuant to coverage-in-place agreements with insurance carriers exist. As a result, any increases in the asbestos reserve have been partially offset by probable insurance recoveries. Ashland has estimated the value of probable insurance recoveries associated with its asbestos reserve based on management's interpretations and estimates surrounding the available or applicable insurance coverage, including an assumption that all solvent insurance carriers remain solvent. The estimated receivable consists exclusively of domestic insurers. Approximately 40% of the receivable is from insurance companies rated by A.M. Best, all of which have a credit rating of A+ or higher as of September 30, 2015.

As of September 30, 2015 and 2014, the receivables from insurers amounted to $56 million and $77 million, respectively. During 2015, the annual update of the model used for purposes of valuing the asbestos reserve and its impact on valuation of future recoveries from insurers was completed. This model update resulted in a $1 million increase in the receivable for probable insurance recoveries.

As a result of the January 2015 asbestos insurance settlement previously described, Hercules has resolved all disputes with Chartis (AIG) member companies under their existing coverage-in-place agreement for past, present and future Hercules asbestos claims. As a result, during 2015, a $22 million reduction in the insurance receivable balance within the Consolidated Balance Sheets was recorded.

A progression of activity in the Hercules insurance receivable is presented in the following table.

(In millions)	2015	2014	2013
Insurance receivable - beginning of year	$ 77	$ 75	$ 56
Receivable adjustment	1	3	19
Insurance settlement	(22)	—	—
Amounts collected	—	(1)	—
Insurance receivable - end of year	$ 56	$ 77	$ 75

Asbestos litigation cost projection

Projecting future asbestos costs is subject to numerous variables that are extremely difficult to predict. In addition to the significant uncertainties surrounding the number of claims that might be received, other variables include the type and severity of the disease alleged by each claimant, the long latency period associated with asbestos exposure, dismissal rates, costs of medical treatment, the impact of bankruptcies of other companies that are co-defendants in claims, uncertainties surrounding the litigation process from jurisdiction to jurisdiction and from case to case, and the impact of potential changes in legislative or judicial standards. Furthermore, any predictions with respect to these variables are subject to even greater uncertainty as the projection period lengthens. In light of these inherent uncertainties, Ashland believes that the asbestos reserves for Ashland and Hercules represent the best estimate within a range of possible outcomes. As a part of the process to develop these estimates of future asbestos costs, a range of long-term cost models was developed. These models are based on national studies that predict the number of people likely to develop asbestos-related diseases and are heavily influenced by assumptions regarding long-term inflation rates for indemnity payments and legal defense costs, as well as other variables mentioned previously. Ashland has currently estimated in various models ranging from approximately 40 to 50 year periods that it is reasonably possible that total future litigation defense and claim settlement costs on an inflated and undiscounted basis could range as high as approximately $880 million for the Ashland asbestos-related litigation (current reserve of $409 million) and approximately $560 million for the Hercules asbestos-related litigation (current reserve of $311 million), depending on the combination of assumptions selected in the various models. If actual experience is worse than projected, relative to the number of claims filed, the severity of alleged disease associated with those

claims or costs incurred to resolve those claims, Ashland may need to increase further the estimates of the costs associated with asbestos claims and these increases could potentially be material over time.

Environmental remediation and asset retirement obligations

Ashland is subject to various federal, state and local environmental laws and regulations that require environmental assessment or remediation efforts (collectively environmental remediation) at multiple locations. At September 30, 2015, such locations included 85 waste treatment or disposal sites where Ashland has been identified as a potentially responsible party under Superfund or similar state laws, 132 current and former operating facilities (including certain operating facilities conveyed as part of the MAP Transaction) and about 1,225 service station properties, of which 63 are being actively remediated.

Ashland's reserves for environmental remediation and related environmental litigation amounted to $186 million at September 30, 2015 compared to $197 million at September 30, 2014, of which $139 million at September 30, 2015 and $158 million at September 30, 2014 were classified in other noncurrent liabilities on the Consolidated Balance Sheets.

The following table provides a reconciliation of the changes in the environmental remediation reserves during 2015 and 2014.

(In millions)	2015	2014
Environmental remediation reserve - beginning of year	$ 197	$ 211
Disbursements	(47)	(46)
Revised obligation estimates and accretion	36	32
Environmental remediation reserve - end of year	$ 186	$ 197

The total reserves for environmental remediation reflect Ashland's estimates of the most likely costs that will be incurred over an extended period to remediate identified conditions for which the costs are reasonably estimable, without regard to any third-party recoveries. Engineering studies, historical experience and other factors are used to identify and evaluate remediation alternatives and their related costs in determining the estimated reserves for environmental remediation. Ashland continues to discount certain environmental sites and regularly adjusts its reserves as environmental remediation continues. Ashland has estimated the value of its probable insurance recoveries associated with its environmental reserve based on management's interpretations and estimates surrounding the available or applicable insurance coverage. At September 30, 2015 and 2014, Ashland's recorded receivable for these probable insurance recoveries were $23 million and $24 million, respectively, of which $16 million and $24 million, respectively, were classified in other noncurrent assets in the Consolidated Balance Sheets.

Components of environmental remediation expense included within the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income are presented in the following table for the years ended September 30, 2015, 2014 and 2013.

(In millions)	2015	2014	2013
Environmental expense	$ 32	$ 29	$ 28
Accretion	4	3	3
Legal expense	6	5	2
Total expense	42	37	33
Insurance receivable	(2)	(4)	(4)
Total expense, net of receivable activity (a)	$ 40	$ 33	$ 29

(a) Net expense of $5 million, $4 million and $6 million for the fiscal years ended September 30, 2015, 2014 and 2013, respectively, relates to divested businesses which qualified for treatment as discontinued operations and for which certain environmental liabilities were retained by Ashland. These amounts are classified within the income from discontinued operations caption of the Statements of Consolidated Comprehensive Income.

Environmental remediation reserves are subject to numerous inherent uncertainties that affect Ashland's ability to estimate its share of the costs. Such uncertainties involve the nature and extent of contamination at each site, the extent of required cleanup efforts under existing environmental regulations, widely varying costs of alternate cleanup methods, changes in environmental regulations, the potential effect of continuing improvements in remediation technology, and the number and financial strength of other potentially responsible parties at multiparty sites. Although it is not possible to predict with certainty the ultimate costs of environmental remediation, Ashland currently estimates that the upper end of the reasonably possible range of future costs for

identified sites could be as high as approximately $370 million. No individual remediation location is significant, as the largest reserve for any site is approximately 14% or less of the remediation reserve.

Insurance settlement

In March 2011, prior to the acquisition of ISP in August 2011, a disruption in the supply of a key raw material for this business occurred at a supplier. For a period of time while the raw material was not available from this supplier, an alternative source was used, but at a higher cost. During 2013, Ashland finalized its settlement with the insurers and received full payment in the amount of $31 million. The insurance settlement resulted in a net gain of $22 million being recognized within the cost of sales caption of the Statement of Consolidated Comprehensive Income during 2013.

Settled claim

During 2013, Ashland settled and collected a claim related to sales commissions and receivables within the Specialty Ingredients reportable segment. To recognize the settlement, Ashland recorded $13 million of income within the equity and other income caption of the Statements of Consolidated Comprehensive Income during 2013.

Other legal proceedings and claims

In addition to the matters described above, there are other various claims, lawsuits and administrative proceedings pending or threatened against Ashland and its current and former subsidiaries. Such actions are with respect to commercial matters, product liability, toxic tort liability, and other environmental matters, which seek remedies or damages, some of which are for substantial amounts. While Ashland cannot predict with certainty the outcome of such actions, it believes that adequate reserves have been recorded and losses already recognized with respect to such actions were immaterial as of September 30, 2015 and 2014. There is a reasonable possibility that a loss exceeding amounts already recognized may be incurred related to these actions; however, Ashland believes that such potential losses were immaterial as of September 30, 2015 and 2014. For additional information on legal proceedings and claims, see the Legal Proceedings section of Form 10-K (Part I, Item 3).

NOTE O – STOCKHOLDERS' EQUITY ITEMS

Stock repurchase programs

During the past three fiscal years, Ashland's Board of Directors has authorized multiple share repurchase programs which are summarized below.

During 2015, Ashland's Board of Directors approved a new $1 billion share repurchase authorization that will expire on December 31, 2017. This authorization allows for common shares to be repurchased in open market transactions, privately negotiated transactions or pursuant to one or more accelerated stock repurchase programs or Rule 10b5-1 plans. During the first quarter of 2016, under this new share repurchase authorization, Ashland announced that it entered into an accelerated share repurchase agreement (November 2015 ASR Agreement) with Goldman, Sachs & Co. Under the November 2015 ASR Agreement, Ashland paid an initial purchase price of $500 million and received an initial delivery of approximately 3.9 million shares of common stock during November 2015. The November 2015 ASR Agreement is scheduled to terminate no later than May 2016 but may be terminated early in certain circumstances, in whole or in part.

During 2014, the Board of Directors of Ashland authorized a $1.35 billion common stock repurchase program (the 2014 stock repurchase program). Under the program, Ashland's common shares were repurchased pursuant to accelerated stock repurchase agreements, a Rule 10b5-1 plan, and a prepaid variable share repurchase agreement. This repurchase program was completed during 2015.

The 2014 stock repurchase program authorization replaced Ashland's previous $600 million share repurchase authorization (the 2013 stock repurchase program), approved in May 2013, which had $450 million remaining when it was terminated.

2014 stock repurchase program agreements

The following stock repurchase agreements were entered into as part of the $1.35 billion common stock repurchase program.

Accelerated stock repurchase agreements

During 2014, Ashland announced that it had entered into accelerated share repurchase agreements (2014 ASR Agreements) with Deutsche Bank AG, London Branch (Deutsche Bank), and JPMorgan Chase Bank, N.A. (JPMorgan) to repurchase an aggregate of $750 million of Ashland's common stock. Under the 2014 ASR Agreements, Ashland paid an initial purchase price of $750 million, split evenly between the financial institutions. As of September 30, 2014, Ashland received an initial delivery of approximately 5.9 million shares of common stock under the 2014 ASR Agreements. The 2014 ASR Agreements had a variable maturity, at the financial institutions option, with a maximum pricing period termination date of June 30, 2015. During 2015, the

2014 ASR Agreements terminated pursuant to their terms and the pricing period was closed. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $116.33 per share. Based on this settlement price, the final number of shares repurchased by Ashland that were delivered by the financial institutions under the 2014 ASR Agreements was 6.4 million shares. Ashland received the additional 0.5 million shares from the financial institutions during 2015 to settle the difference between the initial share delivery and the total number of shares repurchased.

During 2015, Ashland announced and completed accelerated share repurchase agreements (2015 ASR Agreements) with Deutsche Bank and JPMorgan to repurchase an aggregate of $270 million of Ashland's common stock. Under the 2015 ASR Agreements, Ashland paid an initial purchase price of $270 million, split evenly between the financial institutions and received an initial delivery of approximately 1.9 million shares of common stock. The 2015 ASR Agreements had a variable maturity, at the financial institutions option, with a maximum pricing period termination date of July 31, 2015. During 2015, Deutsche Bank and JPMorgan exercised their early termination option under the 2015 ASR Agreements and the pricing period was closed. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $125.22 per share. Based on this settlement price, the final number of shares repurchased by Ashland that were delivered by the financial institutions under the 2015 ASR Agreements was 2.2 million shares. Ashland received the additional 0.3 million shares from the financial institutions during 2015 to settle the difference between the initial share delivery and the total number of shares repurchased.

Additional stock repurchase agreements

Ashland entered into and completed a $125 million prepaid variable share repurchase agreement during 2014. The settlement price, which represents the weighted average price of Ashland's common stock over the pricing period less a discount, was $105.22 per share. Ashland received 0.8 million shares and $45 million in cash for the unused portion of the $125 million prepayment, for a net cash outlay of $80 million.

During 2014, Ashland announced that it had entered into an agreement with each of Deutsche Bank Securities Inc. and JPMorgan to repurchase an aggregate of $250 million of Ashland's common stock. Under the terms of the agreement, the financial institutions purchased a pre-determined number of shares on various trading days dependent upon Ashland's prevailing stock price on that date. During 2014, Ashland received 1.2 million shares of common stock for a total cost of $124 million. During 2015, Ashland completed these agreements, receiving an additional 1.2 million shares of common stock for a total cost of $127 million. The settlement price, which represents the average amount spent after commissions over the common shares repurchased throughout the program, was $104.51 per share. In total, Ashland paid $250 million and received 2.4 million shares of common stock under the agreements.

2013 stock repurchase program agreement

As part of the $600 million common stock repurchase program, Ashland announced and completed an accelerated share repurchase agreement (2013 ASR Agreement) with Citibank, N.A. (Citibank) during 2013. Under the 2013 ASR Agreement, Ashland paid an initial purchase price of $150 million to Citibank and received an initial delivery of approximately 1.3 million shares of its common stock. The 2013 ASR Agreement had a variable maturity, at Citibank’s option, with a maximum pricing period termination date of August 21, 2013. In June 2013, Citibank exercised its early termination option under the 2013 ASR Agreement and the pricing period was closed. The settlement price, which represents the weighted average price of Ashland’s common stock over the pricing period less a discount, was $86.32 per share. Based on this settlement price, the final number of shares repurchased by Ashland that were to be delivered by Citibank under the 2013 ASR Agreement was 1.7 million shares. Ashland received the additional 0.4 million shares from Citibank in 2013 to settle the difference between the initial share delivery and the total number of shares repurchased.

Stockholder dividends

In May 2015, the Board of Directors of Ashland announced a quarterly cash dividend increase to 39 cents per share, $1.56 per share on an annual basis, to eligible shareholders of record. This amount was paid for quarterly dividends in June and September 2015 and was an increase from the quarterly cash dividend of 34 cents per share paid during the first and second quarters of fiscal 2015.

In May 2013, the Board of Directors of Ashland announced a quarterly cash dividend increase to 34 cents per share, $1.36 per share on an annual basis, to eligible shareholders of record. This amount was paid for quarterly dividends in fiscal 2014, as well as, June and September 2013 and was an increase from the quarterly cash dividend of 22.5 cents per share paid during the first and second quarters of fiscal 2013.

Shares reserved for issuance

At September 30, 2015, 8.7 million common shares are reserved for issuance under stock incentive and deferred compensation plans.

NOTE O - STOCKHOLDERS' EQUITY ITEMS (continued)

Accumulated other comprehensive income (loss)

Components of other comprehensive income (loss) recorded in the Statements of Consolidated Comprehensive Income are presented in the following table, before tax and net of tax effects.

(In millions)	Before tax	Tax (expense) benefit	Net of tax
Year ended September 30, 2015			
Other comprehensive income (loss)			
Unrealized translation loss	$ (368)	$ (1)	$ (369)
Pension and postretirement obligation adjustment:			
Adjustment of unrecognized prior service cost	(2)	1	(1)
Amortization of unrecognized prior service credits included in net income (a)	(24)	7	(17)
Unrealized loss on available-for-sale securities	(17)	6	(11)
Total other comprehensive income (loss)	$ (411)	$ 13	$ (398)
Year ended September 30, 2014			
Other comprehensive income (loss)			
Net change in translation gain (loss):			
Unrealized translation loss	$ (163)	$ (3)	$ (166)
Reclassification adjustment for losses included in net income (b)	6	—	6
Pension and postretirement obligation adjustment:			
Adjustment of unrecognized prior service credit	6	(2)	4
Amortization of unrecognized prior service credits included in net income (a)	(36)	11	(25)
Total other comprehensive income (loss)	$ (187)	$ 6	$ (181)
Year ended September 30, 2013			
Other comprehensive income (loss)			
Unrealized translation gain (loss)	$ 45	$ (8)	$ 37
Pension and postretirement obligation adjustment:			
Adjustment of unrecognized prior service credit	13	(3)	10
Amortization of unrecognized prior service credits included in net income (a)	(23)	8	(15)
Net change in interest rate hedges:			
Unrealized loss during period	(3)	—	(3)
Reclassification adjustment for losses included in net income (c)	65	(24)	41
Total other comprehensive income (loss)	$ 97	$ (27)	$ 70

(a) Amortization of unrecognized prior service credits are included in the calculation of net periodic benefit costs (income) for pension and other postretirement plans. For specific financial statement captions impacted by the amortization see the table below.

(b) Losses from the translation adjustment included in net income are attributable to foreign Water Technologies subsidiaries sold with the divestiture. These adjustments are recorded in the discontinued operations caption of the Statements of Consolidated Comprehensive Income.

(c) Losses from interest rate hedges are recorded in the net interest and other financing expense caption of the Statements of Consolidated Comprehensive Income. See Note F for further information.

NOTE O - STOCKHOLDERS' EQUITY ITEMS (continued)

In accordance with U.S. GAAP, as disclosed in the table above, certain pension and other postretirement costs (income) are amortized from accumulated other comprehensive income and recognized in net income. The captions on the Statements of Consolidated Comprehensive Income impacted by the amortization of unrecognized prior service credits for pension and other postretirement plans are disclosed below. See Note M for more information.

(In millions)	2015	2014	2013
Cost of sales	$ (8)	$ (6)	$ (6)
Selling, general and administrative expense	(13)	(14)	(14)
Discontinued operations	(3)	(16)	(3)
Total amortization of unrecognized prior service credits	$ (24)	$ (36)	$ (23)

NOTE P – STOCK INCENTIVE PLANS

Ashland has stock incentive plans under which key employees or directors are granted stock appreciation rights (SARs), performance share awards or nonvested stock awards. Each program is typically a long-term incentive plan designed to link employee compensation with increased shareholder value or reward superior performance and encourage continued employment with Ashland. Ashland recognizes compensation expense for the grant date fair value of stock-based awards over the applicable vesting period. The components of Ashland's pretax stock-based awards (net of forfeitures), which is included in the selling, general and administrative expense caption of the Statements of Consolidated Comprehensive Income, and associated income tax benefits are as follows:

(In millions)	2015 (a)	2014	2013
SARs	$ 10	$ 16	$ 17
Nonvested stock awards	15	10	4
Performance share awards	13	8	9
	$ 38	$ 34	$ 30
Income tax benefit	$ 13	$ 13	$ 11

(a) The year ended September 30, 2015 included a $7 million award modification within performance shares that was designated as a cash item (see table on F-52 for further information) and $1 million of expense related primarily to cash-settled nonvested restricted stock awards.

Stock Appreciation Rights (SARs)

SARs are granted to employees or directors at a price equal to the fair market value of the stock on the date of grant and typically become exercisable over periods of one to three years. Unexercised SARs lapse ten years and one month after the date of grant. Ashland estimates the fair value of SARs granted using the Black-Scholes option-pricing model. This model requires several assumptions, which Ashland has developed and updates based on historical trends and current market observations. The accuracy of these assumptions is critical to the estimate of fair value for these equity instruments. The following table illustrates the weighted-average of key assumptions used within the Black-Scholes option-pricing model. The risk-free interest rate assumption was based on the U.S. Treasury yield curve in effect at the time of the grant for the expected term of the instrument. The dividend yield reflects the assumption that the current dividend payout will continue with no anticipated increases. The volatility assumption was calculated by utilizing an unbiased standard deviation of Ashland's Common Stock closing price for the past five years. The expected life is based on historical data and is not necessarily indicative of exercise patterns that may occur.

(In millions except per share data)	2015	2014	2013
Weighted-average fair value per share of SARs granted	$ 30.70	$ 34.96	$ 29.93
Assumptions (weighted-average)			
Risk-free interest rate	1.7%	1.4%	0.7%
Expected dividend yield	1.2%	1.5%	1.3%
Expected volatility	31.8%	49.7%	55.0%
Expected life (in years)	5	5	5

A progression of activity and various other information relative to SARs and previously issued and vested stock options is presented in the following table.

	2015		2014		2013	
(In thousands except per share data)	Number of common shares	Weighted-average exercise price per share	Number of common shares	Weighted-average exercise price per share	Number of common shares	Weighted-average exercise price per share
Outstanding - beginning of year	1,798	$ 62.85	2,658	$ 55.84	2,908	$ 45.94
Granted	277	113.65	391	89.69	888	70.41
Exercised	(584)	58.80	(1,123)	54.14	(1,037)	39.95
Forfeitures and expirations	(108)	83.00	(128)	75.82	(101)	61.96
Outstanding - end of year (a)	1,383	73.18	1,798	62.85	2,658	55.84
Exercisable - end of year	906	59.92	1,066	53.80	1,390	47.46

(a) Exercise prices per share for SARs outstanding at September 30, 2015 ranged from $9.49 to $49.79 for 139 shares, from $51.86 to $55.73 for 329 shares, from $64.92 to $89.69 for 652 shares, and from $112.91 to $117.38 for 263 shares. The weighted-average remaining contractual life of outstanding SARs and stock options was 6.8 years and exercisable SARs and stock options was 5.9 years.

The total intrinsic value of SARs exercised was $35 million in 2015, $50 million in 2014 and $45 million in 2013. The actual tax benefit realized from the exercised SARs was $6 million in 2015, $18 million in 2014 and $1 million in 2013. The total grant date fair value of SARs that vested during 2015, 2014 and 2013 was $13 million, $21 million and $13 million, respectively. As of September 30, 2015, there was $8 million of total unrecognized compensation costs related to SARs. That cost is expected to be recognized over a weighted-average period of 1.6 years. As of September 30, 2015, the aggregate intrinsic value of outstanding SARs was $41 million and exercisable SARs was $37 million.

Nonvested stock awards

Nonvested stock awards are granted to employees or directors at a price equal to the fair market value of the stock on the date of grant and generally vest over a one-to-five-year period. However, such shares are subject to forfeiture upon termination of service before the vesting period ends. Nonvested stock awards entitle employees or directors to vote the shares. Dividends on nonvested stock awards granted are in the form of additional shares of nonvested stock awards, which are subject to vesting and forfeiture provisions.

A progression of activity and various other information relative to nonvested stock awards is presented in the following table.

	2015		2014		2013	
(In thousands except per share data)	Number of common shares	Weighted-average grant date fair value	Number of common shares	Weighted-average grant date fair value	Number of common shares	Weighted-average grant date fair value
Nonvested - beginning of year	221	$ 88.81	140	$ 56.97	333	$ 33.80
Granted	187	114.97	192	94.17	22	84.12
Vested	(69)	77.51	(78)	47.07	(205)	22.50
Forfeitures	(41)	99.20	(33)	83.84	(10)	51.01
Nonvested - end of year	298	106.41	221	88.81	140	56.97

The total fair value of nonvested stock awards that vested during 2015, 2014 and 2013 was $5 million, $4 million and $5 million, respectively. As of September 30, 2015, there was $15 million of total unrecognized compensation costs related to nonvested stock awards. That cost is expected to be recognized over a weighted-average period of 1.7 years.

Performance shares

Ashland sponsors a long-term incentive plan that awards performance shares/units to certain key employees that are tied to Ashland's overall financial performance relative to the financial performance of selected industry peer groups and/or internal targets. Awards are granted annually, with each award covering a three-year performance cycle. Each performance share/unit is convertible to one share of Ashland Common Stock. These plans are recorded as a component of stockholders' equity in the Consolidated Balance Sheets. Performance measures used to determine the actual number of performance shares issuable upon

vesting include an equal weighting of Ashland's total shareholder return (TSR) performance and Ashland's return on investment (ROI) performance as compared to the internal targets over the three-year performance cycle. TSR relative to peers is considered a market condition while ROI is considered a performance condition under applicable U.S. GAAP. Nonvested performance shares/units do not entitle employees to vote the shares or to receive any dividends thereon.

The following table shows the performance shares/units granted for all plans that award Ashland Common Stock.

(In thousands)	Performance period	Target shares granted (a)	Weighted-average fair value per share
Fiscal Year 2015	October 1, 2014 - September 30, 2017	77	$ 121.87
Fiscal Year 2014	October 1, 2013 - September 30, 2016	110	$ 85.84
Fiscal Year 2013	October 1, 2012 - September 30, 2015	134	$ 73.50

(a) At the end of the performance period, the actual number of shares issued can range from zero to 200% of the target shares granted, which is assumed to be 100%.

The fair value of the ROI portion of the performance share awards is equal to the fair market value of Ashland's Common Stock on the date of the grant discounted for the dividends forgone during the vesting period of the three-year performance cycle. Compensation cost is recognized over the requisite service period if it is probable that the performance condition will be satisfied. The fair value of the TSR portion of the performance share awards is calculated using a Monte Carlo simulation valuation model using key assumptions included in the following table. Compensation cost is recognized over the requisite service period regardless of whether the market condition is satisfied.

	2015	2014	2013
Risk-free interest rate	0.1% - 1.0%	0.1% - 0.6%	0.2% - 0.3%
Expected dividend yield	1.4%	1.4%	1.3%
Expected life (in years)	3	3	3
Expected volatility	24.2%	32.1%	37.6%

The following table shows changes in nonvested performance shares/units for all plans that award Ashland Common Stock.

	2015		2014		2013	
(In thousands except per share data)	Shares	Weighted-average grant date fair value	Shares	Weighted-average grant date fair value	Shares	Weighted-average grant date fair value
Nonvested - beginning of year	368	$ 72.20	433	$ 65.05	480	$ 54.39
Granted (a)	103	115.19	155	81.09	152	69.74
Vested (a)	(133)	68.18	(183)	62.05	(175)	39.55
Forfeitures (b)	(134)	74.79	(37)	75.02	(24)	67.06
Nonvested - end of year	204	93.79	368	72.20	433	65.05

(a) The current year includes 26 additional shares from the fiscal 2012 through 2014 plan, 2014 includes 45 additional shares from the fiscal 2011 through 2013 plan and 2013 includes 18 additional shares from the fiscal 2010 through 2012 plan since a portion of each plans payout was in excess of the initial 100% target.

(b) During the December 2014 quarter, Ashland modified certain awards of its performance shares. The awards were modified to provide that the instruments be paid in cash instead of stock. This change in payment designation caused Ashland to recognize $7 million in incremental stock-based compensation expense related to 84 shares modified during 2015.

As of September 30, 2015, there was $8 million of total unrecognized compensation costs related to nonvested performance share awards. That cost is expected to be recognized over a weighted-average period of approximately 1.8 years.

NOTE Q – REPORTABLE SEGMENT INFORMATION

Ashland determines its reportable segments based on how operations are managed internally for the products and services sold to customers, including how the results are reviewed by the chief operating decision maker, which includes determining resource allocation methodologies used for reportable segments. Operating income is the primary measure reviewed by the chief operating decision maker in assessing each reportable segment's financial performance. Ashland does not aggregate operating segments to arrive at these reportable segments. Subsequent to the sale of Water Technologies and a business realignment during 2014, Ashland's businesses are managed within three reportable segments: Specialty Ingredients, Performance Materials and Valvoline.

The 2014 business realignment resulted in the re-organization of Specialty Ingredients into two divisions: Consumer Specialties and Industrial Specialties, with the adhesives category joining the Industrial Specialties division, moving over from Performance Materials. While, Performance Materials became comprised of three divisions: 1) Intermediates/Solvents, which moved over from Specialty Ingredients and serves both Ashland's internal butanediol needs as well as the merchant market; 2) Composites, which serves construction, transportation, marine and other markets; and 3) Elastomers, which primarily served the North American replacement tire market prior to its December 1, 2014 sale. The business realignment during 2014 did not affect the Valvoline business, as it remained unchanged compared to prior year periods.

Ashland performed an internal structural review and comprehensive assessment of its operations and reportable segments and concluded that its operating and reportable segments were Specialty Ingredients, Performance Materials, and Valvoline.

Reportable segment business descriptions

Specialty Ingredients is a global leader in cellulose ethers, vinyl pyrrolidones and biofunctionals. It offers industry-leading products, technologies and resources for solving formulation and product-performance challenges. Specialty Ingredients uses natural, synthetic and semisynthetic polymers derived from plant and seed extract, cellulose ethers, vinyl pyrrolidones, acrylic polymers as well as polyester and polyurethane-based adhesives. Specialty Ingredients includes two divisions, Consumer Specialties and Industrial Specialties, that offer comprehensive and innovative solutions for today's demanding consumer and industrial applications. Key customers include: pharmaceutical companies; makers of personal care products, food and beverages; manufacturers of paint, coatings and construction materials; packaging and converting; and oilfield service companies. During 2015, Ashland sold the industrial biocides assets within Specialty Ingredients. See Note B for information on the divestiture of these assets.

Performance Materials is composed of two divisions: Composites and Intermediates/Solvents. Performance Materials is a global leader in unsaturated polyester resins and vinyl ester resins. The business unit has leading positions in gelcoats, maleic anhydride, butanediol, tetrahydrofuran, N-Methylpyrrolidone and other intermediates and solvents. Key customers include: manufacturers of residential and commercial building products; industrial product specifiers and manufacturers; wind blade and pipe manufacturers; automotive and truck OEM suppliers; boatbuilders; engineered plastics and electronic producers; and specialty chemical manufacturers. Results from the former Elastomers division were included in Performance Materials' results of operations within the Statements of Consolidated Comprehensive Income until its December 1, 2014 sale. See Note B for information on the divestiture of the Elastomers division.

Valvoline is a leading, worldwide producer and distributor of premium-branded automotive, commercial and industrial lubricants and automotive chemicals. It ranks as the #2 quick-lube chain and #3 passenger car motor oil brand in the United States. The brand operates and franchises approximately 940 Valvoline Instant Oil Change℠ centers in the United States. It also markets Valvoline™ lubricants and automotive chemicals; MaxLife™ lubricants created for higher-mileage engines; SynPower™ synthetic motor oil; and Zerex™ antifreeze. Key customers include: retail auto parts stores and mass merchandisers who sell to consumers; installers, such as car dealers, repair shops and quick lubes; commercial fleets; and distributors. During 2015, Ashland sold its Valvoline car care product assets, including Car Brite™ and Eagle One™ automotive appearance products, and sold its joint venture equity investment in Venezuela. See Note B for information on the divestiture of this investment and the car care product assets.

Unallocated and Other generally includes items such as components of pension and other postretirement benefit plan expenses (excluding service costs, which are allocated to the reportable segments), certain significant company-wide restructuring activities and legacy costs or adjustments that relate to divested businesses that are no longer operated by Ashland, including the Water Technologies business.

International data

Information about Ashland's domestic and international operations follows. Ashland has no material operations in any individual international country and no single customer represented more than 10% of sales in 2015, 2014 or 2013.

	Sales from external customers			Net assets (liabilities)		Property, plant and equipment - net	
(In millions)	2015	2014	2013	2015	2014	2015	2014
United States	$ 2,715	$ 3,076	$ 3,130	$ (575)	$ (160)	$ 1,569	$ 1,721
International	2,672	3,045	2,961	3,612	3,743	613	693
	$ 5,387	$ 6,121	$ 6,091	$ 3,037	$ 3,583	$ 2,182	$ 2,414

Reportable segment results

The following tables present various financial information for each reportable segment for the years ended September 30, 2015, 2014 and 2013 and as of September 30, 2015, 2014 and 2013. Results of Ashland's reportable segments are presented based on its management structure and internal accounting practices. The structure and practices are specific to Ashland; therefore, the financial results of Ashland's reportable segments are not necessarily comparable with similar information for other comparable companies. Ashland allocates all costs to its reportable segments except for certain significant company-wide restructuring activities, such as the restructuring plans described in Note E, and other costs or adjustments that relate to former businesses that Ashland no longer operates. The service cost component of pension and other postretirement benefits costs is allocated to each reportable segment on a ratable basis; while the remaining components of pension and other postretirement benefits costs are recorded to Unallocated and other. Ashland refines its expense allocation methodologies to the reportable segments from time to time as internal accounting practices are improved, more refined information becomes available and the industry or market changes. Revisions to Ashland's methodologies that are deemed insignificant are applied on a prospective basis.

Ashland determined that disclosing sales by specific product was impracticable due to the highly customized and extensive portfolio of products offered to customers and since no one product or a small group of products could be aggregated together to represent a majority of revenue within a reportable segment. As such, the following table provides a summary of 2015 sales by product category for each reportable segment:

Sales by product category for 2015					
Specialty Ingredients		Performance Materials		Valvoline	
Cellulosics	37%	Composites	68%	Lubricants	86%
Poly vinyl pyrrolidones	18%	Intermediates/Solvents	28%	Chemicals (c)	7%
Adhesives	13%	Elastomers (b)	4%	Antifreeze	5%
Vinyl ethers	7%		100%	Filters	2%
Actives	6%				100%
Guar	2%				
Other (a)	17%				
	100%				

(a) Includes sales for biocides through July 1, 2015 sale.
(b) Includes sales only through December 1, 2014 sale.
(c) Includes sales for car care products through June 30, 2015 sale.

The following table presents various financial information for each reportable segment. The operating results of divested divisions and assets during 2015, 2014 and 2013 that did not qualify for discontinued operations accounting treatment are included in the financial information until the date of sale.

NOTE Q – REPORTABLE SEGMENT INFORMATION (continued)

Ashland Inc. and Consolidated Subsidiaries
Reportable Segment Information
Years Ended September 30

(In millions)	2015	2014	2013
Sales			
Specialty Ingredients	$ 2,263	$ 2,498	$ 2,478
Performance Materials	1,157	1,582	1,617
Valvoline	1,967	2,041	1,996
	$ 5,387	$ 6,121	$ 6,091
Equity income (expense)			
Specialty Ingredients	$ 1	$ 2	$ 4
Performance Materials	2	(38)	10
Valvoline	(2)	10	13
Unallocated and other	—	1	(1)
	1	(25)	26
Other income (expense)			
Specialty Ingredients	(1)	(2)	14
Performance Materials	5	5	6
Valvoline	10	20	11
Unallocated and other	8	4	7
	22	27	38
	$ 23	$ 2	$ 64
Operating income (loss)			
Specialty Ingredients	$ 239	$ 253	$ 243
Performance Materials	87	7	106
Valvoline	359	323	295
Unallocated and other	(227)	(537)	395
	$ 458	$ 46	$ 1,039
Assets			
Specialty Ingredients	$ 5,365	$ 5,756	$ 5,994
Performance Materials	1,079	1,395	1,518
Valvoline	976	1,073	1,051
Unallocated and other	2,644	2,696	3,488
	$ 10,064	$ 10,920	$ 12,051

Ashland Inc. and Consolidated Subsidiaries
Reportable Segment Information (continued)
Years Ended September 30

(In millions)	2015	2014	2013
Equity and other unconsolidated investments			
Specialty Ingredients	$ 9	$ 10	$ 12
Performance Materials (a)	24	23	157
Valvoline (b)	29	44	40
Unallocated and other	3	4	4
	$ 65	$ 81	$ 213
Depreciation and amortization			
Specialty Ingredients	$ 244	$ 262	$ 242
Performance Materials	59	91	75
Valvoline	38	37	35
Unallocated and other	—	3	4
	$ 341	$ 393	$ 356
Property, plant and equipment - net			
Specialty Ingredients	$ 1,383	$ 1,433	$ 1,445
Performance Materials	358	508	551
Valvoline	253	272	270
Unallocated and other	188	201	241
	$ 2,182	$ 2,414	$ 2,507
Additions to property, plant and equipment			
Specialty Ingredients	$ 171	$ 159	$ 144
Performance Materials	33	38	43
Valvoline	45	36	41
Unallocated and other	16	15	36
	$ 265	$ 248	$ 264

(a) ASK joint venture sold during 2014.
(b) Venezuela joint venture sold during 2015.

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The following table presents quarterly financial information and per share data relative to Ashland's Common Stock.

Quarters ended	December 31		March 31		June 30		September 30	
(In millions except per share data)	2014	2013	2015	2014	2015	2014	2015 (a)	2014 (b)
Sales	$ 1,391	$ 1,432	$ 1,350	$ 1,545	$ 1,367	$ 1,605	$ 1,280	$ 1,538
Cost of sales	982	1,048	925	1,168	939	1,161	970	1,227
Gross profit as a percentage of sales	29.4%	26.8%	31.5%	24.4%	31.3%	27.7%	24.2%	20.2%
Operating income (loss)	169	143	193	(64)	196	143	(101)	(175)
Income (loss) from continuing operations	40	88	95	(61)	115	71	(59)	(26)
Net income (loss)	32	110	224	(44)	107	99	(55)	68
Basic earnings per share								
Continuing operations	$ 0.58	$ 1.14	$ 1.40	$ (0.78)	$ 1.70	$ 0.91	$ (0.88)	$ (0.35)
Net income (loss)	0.47	1.42	3.30	(0.57)	1.58	1.27	(0.82)	0.93
Diluted earnings per share								
Continuing operations	$ 0.57	$ 1.12	$ 1.39	$ (0.78)	$ 1.68	$ 0.90	$ (0.88)	$ (0.35)
Net income (loss)	0.46	1.40	3.26	(0.57)	1.56	1.25	(0.82)	0.93
Regular cash dividends per share	$ 0.34	$ 0.34	$ 0.34	$ 0.34	$ 0.39	$ 0.34	$ 0.39	$ 0.34
Market price per common share								
High	$ 121.35	$ 97.68	$ 130.66	$ 100.87	$ 132.38	$ 108.93	$ 123.60	$ 110.02
Low	95.21	84.43	115.66	88.76	121.83	93.62	97.58	98.55

(a) Fourth quarter results for 2015 include a decrease in operating income of $246 million related to the loss on pension and postretirement benefit plan remeasurement ($97 million in cost of sales and $149 million in selling, general and administrative expenses), a decrease of $13 million for a customer claim, a decrease of $11 million related to the impairment on IPR&D assets associated with the ISP acquisition, a decrease of $6 million related to restructuring and a decrease of $3 million for an environmental reserve adjustment. Income tax benefit for the fourth quarter included $6 million of discrete tax income items.

(b) Fourth quarter results for 2014 include a decrease in operating income of $317 million related to the loss on pension and postretirement benefit plan remeasurement ($97 million in cost of sales and $220 million in selling, general and administrative expenses), a decrease of $29 million related to restructuring and plant closure costs, a decrease of $5 million for foreign legal reserves and a decrease of $4 million related to the impairment on IPR&D assets associated with the ISP acquisition. Income tax benefit for the fourth quarter included $100 million of discrete tax income items including a $168 million reversal of a deferred tax liability related to an assertion change of the nature of unremitted earnings of foreign subsidiaries.

Ashland Inc. and Consolidated Subsidiaries

Five-Year Selected Financial Information

Years Ended September 30

(In millions except per share data)	2015	2014	2013	2012	2011
Summary of operations					
Sales	$ 5,387	$ 6,121	$ 6,091	$ 6,472	$ 4,600
Cost of sales	3,814	4,605	4,304	4,813	3,563
Gross profit	1,573	1,516	1,787	1,659	1,037
Selling, general and administrative expense	1,028	1,358	670	1,327	980
Research and development expense	110	114	142	104	49
Equity and other income	23	2	64	53	45
Operating income	458	46	1,039	281	53
Net interest and other financing expense	174	166	282	317	121
Net gain (loss) on divestitures	(115)	4	(8)	(7)	2
Other expense (income)	—	—	—	—	1
Income (loss) from continuing operations before income taxes	169	(116)	749	(43)	(67)
Income tax expense (benefit)	(22)	(188)	196	(57)	(70)
Income from continuing operations	191	72	553	14	3
Income from discontinued operations	118	161	130	12	411
Net income	$ 309	$ 233	$ 683	$ 26	$ 414
Balance sheet information (as of September 30)					
Current assets	$ 3,248	$ 3,561	$ 2,873	$ 3,209	$ 3,387
Current liabilities	1,448	1,687	1,727	1,913	1,739
Working capital	$ 1,800	$ 1,874	$ 1,146	$ 1,296	$ 1,648
Total assets	$ 10,064	$ 10,920	$ 12,051	$ 12,471	$ 12,893
Short-term debt	$ 326	$ 329	$ 308	$ 344	$ 83
Long-term debt (including current portion and debt issuance cost discounts)	3,403	2,920	2,922	3,193	3,676
Stockholders' equity	3,037	3,583	4,553	4,029	4,135
Cash flow information					
Cash flows from operating activities from continuing operations	$ 89	$ 580	$ 653	$ 189	$ 50
Additions to property, plant and equipment	265	248	264	242	152
Cash dividends	98	103	88	63	51
Common stock information					
Basic earnings per share					
Income from continuing operations	$ 2.81	$ 0.94	$ 7.06	$ 0.18	$ 0.05
Net income	4.54	3.04	8.71	0.33	5.28
Diluted earnings per share					
Income from continuing operations	2.78	0.93	6.95	0.17	0.05
Net income	4.48	3.00	8.57	0.33	5.17
Dividends	1.46	1.36	1.13	0.80	0.65

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ATTACHMENT B

SEC FORM 10-K FOR CLEAN HARBORS, INC.

Table Of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2015

OR

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

For the transition period from to .

COMMISSION FILE NO. 001-34223

CLEAN HARBORS, INC.

(Exact name of registrant as specified in its charter)

Massachusetts (State or other jurisdiction of incorporation or organization)	**04-2997780** (IRS Employer Identification No.)
42 Longwater Drive, Norwell, MA (Address of principal executive offices)	**02061-9149** (Zip Code)

Registrant's telephone number: (781) 792-5000

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class:	Name of each exchange on which registered:
Common Stock, $.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Securities Exchange Act of 1934:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

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

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

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

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

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

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

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

On June 30, 2015 (the last business day of the registrant's most recently completed second fiscal quarter), the aggregate market value of the voting and non-voting common stock of the registrant held by non-affiliates of the registrant was approximately $2.9 billion, based on the closing price of such common stock as of that date on the New York Stock Exchange. Reference is made to Part III of this report for the assumptions on which this calculation is based.

On February 19, 2016, there were outstanding 57,604,283 shares of Common Stock, $.01 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Certain portions of the registrant's definitive proxy statement for its 2016 annual meeting of stockholders (which will be filed with the Commission not later than April 30, 2016) are incorporated by reference into Part III of this report.

CLEAN HARBORS, INC.

ANNUAL REPORT ON FORM 10-K

YEAR ENDED DECEMBER 31, 2015

TABLE OF CONTENTS

		Page No
Part I		
Item 1.	Business	1
Item 1A.	Risk Factors	14
Item 1B.	Unresolved Staff Comments	23
Item 2.	Properties	23
Item 3.	Legal Proceedings	25
Item 4.	Mine Safety Disclosures	25
Part II		
Item 5.	Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	26
Item 6.	Selected Financial Data	28
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	29
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	50
Item 8.	Financial Statements and Supplementary Data	51
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	103
Item 9A.	Controls and Procedures	103
Item 9B.	Other Information	105
Part III		
Item 10.	Directors, Executive Officers and Corporate Governance	105
Item 11.	Executive Compensation	105
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	105
Item 13.	Certain Relationships and Related Transactions, and Director Independence	105
Item 14.	Principal Accountant Fees and Services	105
Part IV		
Item 15.	Exhibits and Financial Statement Schedules	106
SIGNATURES		107

Disclosure Regarding Forward-Looking Statements

In addition to historical information, this annual report contains forward-looking statements, which are generally identifiable by use of the words "believes," "expects," "intends," "anticipates," "plans to," "estimates," "projects," or similar expressions. These forward-looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those reflected in these forward-looking statements. Factors that might cause such a difference include, but are not limited to, those discussed in this report under Item 1A, "Risk Factors," and Item 7, "Management's Discussion and Analysis on Financial Condition and Results of Operations." Readers are cautioned not to place undue reliance on these forward-looking statements, which reflect management's opinions only as of the date hereof. We undertake no obligation to revise or publicly release the results of any revision to these forward-looking statements. Readers should also carefully review the risk factors described in other documents which we file from time to time with the Securities and Exchange Commission (the "SEC"), including the quarterly reports on Form 10-Q to be filed by us during 2016.

PART I

ITEM 1. BUSINESS

General

Clean Harbors, Inc. and its subsidiaries (collectively, "we," "Clean Harbors" or the "Company") is a leading provider of environmental, energy and industrial services throughout North America.

Our operations are managed in six reportable segments: Technical Services, Industrial and Field Services which consists of the Industrial Services and Field Services operating segments, Kleen Performance Products, SK Environmental Services, Lodging Services and Oil and Gas Field Services.

- **Technical Services** — provides a broad range of hazardous material management services including the packaging, collection, transportation, treatment and disposal of hazardous and non-hazardous waste at our incineration, landfill, wastewater and other treatment facilities.

- **Industrial and Field Services** — provides industrial and specialty services such as high-pressure and chemical cleaning, catalyst handling, decoking and material processing to refineries, chemical plants, oil sands facilities, pulp and paper mills, and other industrial facilities. Also provides a wide variety of environmental cleanup services on customer sites or other locations on a scheduled or emergency response basis including tank cleaning, decontamination, remediation, and spill cleanup.

- **Kleen Performance Products** ***(formerly Oil Re-refining and Recycling)*** — processes used oil into high quality base and blended lubricating oils which are then sold to third party customers, and provides recycling of oil in excess of our current re-refining capacity into recycled fuel oil which is then sold to third parties. Processing into base and blended lubricating oils takes place in our three owned and operated re-refineries and recycling of oil into recycled fuel oil takes place in one of our used oil terminals.

- **SK Environmental Services** — consists of Safety-Kleen's branches and provides a broad range of environmental services such as parts cleaning, containerized waste services, used oil collection, and other complementary products and services, including vacuum services, allied products and other environmental services.

- **Lodging Services** — provides lodges and remote workforce accommodation facilities throughout Western Canada. These include both client and open lodges, operator camps, and drill camps. Also included within the segment are manufacturing of modular units and wastewater processing plants, operating services and parts.

- **Oil and Gas Field Services** — provides fluid handling, fluid hauling, production servicing, surface rentals, seismic services, and directional boring services to the energy sector serving oil and gas exploration and production, and power generation.

Clean Harbors, Inc. was incorporated in Massachusetts in 1980 and our principal office is located in Norwell, Massachusetts. We maintain a website at the following Internet address: http://www.cleanharbors.com. Through a link on this website to the SEC website, http://www.sec.gov, we provide free access to our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after electronic filing with the SEC. Our guidelines on corporate governance, the charters for our board committees, and our code of ethics for members of the board of directors, our chief executive officer and our other senior officers are also available on our website, and we will post on our

website any waivers of, or amendments to, such code of ethics. Our website and the information contained therein or connected thereto are not incorporated by reference into this annual report.

Health and Safety

Health and Safety is our #1 priority—companywide. Employees at all levels of our Company share this philosophy and are committed to ensuring our safety goals are met. Our commitment to health and safety benefits everyone—our employees, our customers, the community, and the environment. In 2015 we continued with our very successful *Safety Starts With Me: Live It 3-6-5* program which is a key component in our overall safety program and along with our many other programs has continued to lower our Total Recordable Incident Rate, or "TRIR;" Days Away, Restricted Activity and Transfer Rate, or "DART;" and Experience Modification Rate, or "EMR." For the year ended December 31, 2015, our Company wide TRIR, DART and EMR were 1.33, 0.83 and 0.54, respectively. For the year ended December 31, 2014, our Company wide TRIR, DART and EMR were 1.57, 1.01 and 0.54, respectively.

In order to protect our employees, continue to lower our incident rates, and satisfy our customers' demands to retain the best service providers with the lowest TRIR, DART and EMR rates, we are fully committed to continuously improving our health and safety performance. All employees recognize the importance of protecting themselves, their fellow employees, their customers, and all those around them from harm. This commitment is supported by the philosophies and Golden Rules of Safety that is the cornerstone of the Safety Starts with Me: Live It 3-6-5 program. Live It 3-6-5 is our dedication to the safety of our workers through each and every employee’s commitment to our three Safety philosophies, our six Golden Rules of Safety and each employee’s five personal reasons why they choose to be safe both at work, on the road and at home.

Compliance

We regard compliance with applicable environmental regulations as a critical component of our overall operations. We strive to maintain the highest professional standards in our compliance activities. Our internal operating requirements are in many instances more stringent than those imposed by regulation. Our compliance program has been developed for each of our waste management facilities and service centers under the direction of our compliance staff. The compliance staff is responsible for facilities permitting and regulatory compliance, compliance training, transportation compliance, and related record keeping. To ensure the effectiveness of our regulatory compliance program, our compliance staff monitors daily operational activities. We also have an Environmental Health and Safety Compliance Internal Audit Program designed to identify any weaknesses or opportunities for improvement in our ongoing compliance programs. We also perform periodic audits and inspections of the disposal facilities owned by other companies which we utilize.

Our facilities are frequently inspected and audited by regulatory agencies, as well as by customers. Although our facilities have been cited on occasion for regulatory violations, we believe that each of our facilities is currently in substantial compliance with applicable permit requirements.

Strategy

Our strategy is to develop and maintain ongoing relationships with a diversified group of customers that have recurring needs for environmental, energy or industrial services. We strive to be recognized as the premier supplier of a broad range of value-added services based upon quality, responsiveness, customer service, information technologies, breadth of service offerings and cost effectiveness.

The principal elements of our business strategy are to:

- **Expand Service Offerings and Geographic Coverage**—We believe our Technical, Industrial and Field Services, and SK Environmental segments have a competitive advantage, particularly in areas where we maintain service locations at or near a treatment, storage and disposal facility, or "TSDF." By opening additional service locations in close proximity to our TSDFs, we believe that we can, with minimal capital expenditures, increase our market share within the Industrial and Field Services segment. We believe this will drive additional waste to our existing facilities, thereby increasing utilization and enhancing overall profitability.
- **Cross-Sell Across Segments**—We believe the breadth of our service offerings allows us to provide additional services to existing customers. In particular, we believe we can provide industrial and field services to customers that traditionally have only used our technical services and technical services to customers that use our industrial services or oil and gas field services. At the same time, we see a variety of cross-selling opportunities between our Technical, Industrial and Field Services offerings and SK Environmental Services’ 200,000 customers. Evidencing this strategy, we have been successfully cross selling the services of Safety-Kleen, Inc. ("Safety-Kleen"), since our acquisition of Safety-Kleen in December 2012, such as parts washers, Allied products and recycling services, to legacy Clean

Harbors customers. We believe leveraging our ability to cross-sell across all of our segments will drive additional revenue for our Company.

- **Capture Large-Scale Projects**—We provide turnkey offsite transportation and landfill or incineration disposal services for soil and other contaminated media generated from remediation activities. We also assist remediation contractors and project managers with support services including groundwater disposal, investigation derived waste disposal, rolloff container management, and many other related services. We believe this will drive incremental waste volume to our existing facilities, thereby increasing utilization and enhancing overall profitability.
- **Expand Throughput Capacity of Existing Waste Facilities**—We operate an extensive network of hazardous waste management facilities and have made substantial investments in these facilities, which provide us with significant operating leverage as volumes increase. In addition, there are opportunities to expand waste handling capacity at these facilities by modifying the terms of the existing permits and by adding equipment and new technology. Through selected permit modifications, we can expand the range of treatment services offered to our customers without the large capital investment necessary to acquire or build new waste management facilities.
- **Pursue Selective Acquisitions**—We actively pursue accretive acquisitions in certain services or market sectors where we believe the acquisitions can enhance and expand our business, such as the oil collection and refinery markets. We believe that we can expand existing services, especially in our non-disposal services, through strategic acquisitions in order to generate incremental revenues from existing and new customers and to obtain greater market share.
- **Execute Strategic Mergers and Divestitures**—To complement our acquisition strategy and our focus on internal growth, we regularly review and evaluate our existing operations to determine whether our business model should change through the merger or divestiture of certain businesses. Accordingly, from time to time, we may merge or divest certain non-core businesses and reallocate our resources to businesses that better align with our long-term strategic direction.
- **Focus on Cost, Pricing and Productivity Initiatives**—We continually seek to increase efficiency and to reduce costs in our business through enhanced technology, process efficiencies and stringent expense management. For instance, in 2014, we successfully executed a significant cost reduction program that included headcount reductions, branch consolidations, reduction in third-party rentals, greater internalization of maintenance costs, procurement and supply chain improvements and lowering reliance on outside transportation.

Acquisitions and Other Business Transactions

Acquisitions are an element of our business strategy that involves expansion through the acquisition of businesses that complement our existing company and create multiple opportunities for profitable growth.

On February 3, 2016, we purchased a re-refinery facility located in Nevada from Vertex Energy, Inc. for a purchase price of $35.0 million in cash, subject to customary post-closing adjustments. The acquired re-refinery facility further expands our re-refinery network within our Kleen Performance Products segment.

On April 11, 2015, we acquired Thermo Fluids Inc. (“TFI”) for approximately $78.6 million inclusive of current estimates of and subject to certain closing and post-closing adjustments relating to working capital and other assumed liabilities. TFI provides environmental services, including used oil recycling, used oil filter recycling, antifreeze products, parts washers and solvent recycling, and industrial waste management services, including vacuum services, remediation, lab pack and hazardous waste management. The acquisition expands our environmental services customer base while also complimenting the SK Environmental Services network and presence in the western United States.

In December 2015, we acquired certain assets and assumed certain defined liabilities of a privately owned company for approximately $14.7 million in cash. That Company specialized in the collection and recycling of used oil filters and was a service provider to the SK Environmental Services segment prior to the acquisition. The acquired company has been integrated into the SK Environmental Services segment.

In 2014, we acquired the assets of two privately owned companies for approximately $16.1 million in cash, net of cash acquired. The purchase price is subject to customary post-closing adjustments based upon finalized working capital amounts. The acquired companies have been integrated into the Technical Services and Lodging Services segments.

On September 13, 2013, we acquired all of the outstanding shares of Evergreen Oil, Inc. (“Evergreen”) for approximately $56.3 million in cash, net of cash acquired. Evergreen, headquartered in Irvine, California, specializes in the recovery and re-refining of used oil. Evergreen owns and operates an oil re-refining operation in the western United States and also offers other ancillary environmental services, including parts cleaning and containerized waste services, vacuum services and hazardous waste management services. The acquisition of Evergreen enables us to further penetrate the small quantity waste generator

market and further expand its oil re-refining, oil recycling and waste treatment capabilities. Financial information and results of Evergreen have been recorded in our consolidated financial statements since acquisition and are primarily included in the Kleen Performance Products segment.

For additional information relating to our acquisition activities during fiscal years 2015, 2014 and 2013, see Note 3, "Business Combinations," to our consolidated financial statements included in Item 8 of this report.

Other business transactions may consist of mergers or divestitures and is another element of our business strategy that involves review of our portfolio of assets to determine the extent to which they are contributing to our objectives and growth strategy.

We have announced a planned carve-out of our Oil and Gas Field Services and Lodging Services segments into a standalone public company. Ultimate completion of the planned transaction is subject to certain conditions including, but not limited to, market conditions, determination of the most advantageous structure from a financial and tax standpoint, overall costs to our Company, receipt of regulatory approvals, compliance with our debt covenants, the effectiveness of securities laws filings and final approval by our board of directors. There can be no assurance regarding the ultimate structure and timing of the proposed transaction or whether the transaction will be completed.

Protecting the Environment and Corporate Sustainability

Our core business is to provide industry, government and the public a wide range of environmental, energy and industrial services that protect and restore North America's natural environment.

As North America's premier provider of environmental as well as energy and industrial services, our first goal is to help our customers prevent the release of hazardous wastes into the environment. We also are the leading service provider in the recovery and decontamination of pollutants that have been released to the environment. This includes the safe destruction or disposal of hazardous materials in a manner that ensures these materials are no longer a danger to the environment. When providing these services, we are committed to the recycling, reuse and reclamation of these wastes whenever possible using a variety of methods more fully explained below in the sections describing our general operations. Our Safety-Kleen branded services exemplify our commitment to sustainability and providing environmental solutions to the marketplace. Where possible, liquids such as solvents, chemicals and used oil are recycled to our high-quality standards and made into useful products. Tolling programs provide a closed-loop cycle in which the customer’s spent solvents are recycled to their precise specifications and returned directly to them.

We have become the leading North American provider of services to protect the ozone layer from the destructive effects of chlorofluorocarbons, or "CFCs," which are ozone layer depleting substances and global warming compounds that have global warming potentials up to 10,000 times more powerful than carbon dioxide. Global-warming potential is a relative measure of how much heat a green house gas traps in the atmosphere.

Since 2013, California Air Resources Board has issued over 7,000,000 emission reduction credits that were generated by destroying CFC’s at Clean Harbors’ El Dorado Arkansas incinerator. Over 7,000,000 metric tons of carbon dioxide emissions were avoided by destroying these greenhouse gases. That is equivalent to removing over 1,473,684 passenger vehicles from the road for one year .

One of our most highly visible public programs for various governmental and community entities involves the removal of thousands of tons of hazardous wastes, from households throughout the United States and Canada, that might otherwise be improperly disposed of or become dangerous to the communities where they are stored.

As we provide these wide-ranging services throughout North America, we are committed to ensuring that our own operations are environmentally responsible. Our sustainability efforts are guided by a formal policy, strategy and plan and we continue to build on our past efforts, such as implementing numerous energy efficiency improvements and various transportation initiatives. Our 1.5 Mw solar array at a closed and capped landfill in New Jersey continues to provide virtually all of the power for the ongoing operation of the onsite ground water decontamination pump and treatment system.

Competitive Strengths

- **Leading Provider of Environmental, Energy and Industrial Services**—We are one of the largest providers of environmental, energy and industrial services and the largest operator of non-nuclear hazardous waste treatment facilities in North America. We provide multi-faceted and low cost services to a broad mix of customers. We attract and better serve our customers because of our capabilities and the size, scale and geographic location of our assets, which allow us to serve multiple locations. Based on latest industry data, we service approximately 65% of North America's commercial hazardous incineration volume and 24% of North America's hazardous landfill volume.

- **Largest collector and recycler of used motor oil**— As the largest re-refiner and recycler of used oil in the world, we returned approximately 160 million gallons of new re-refined oil, lubricants and byproducts back into the marketplace. In 2015, our re-refining process eliminated over one million metric tons of greenhouse gas ("GHG"), which is the equivalent of growing more than 32 million trees for 10 years in an urban environment, or taking over 200,000 passenger cars off the road for one year.
- **Large and Diversified Customer Base**—Our customers range from Fortune 500 companies to midsize and small public and private entities that span multiple industries and business types, including governmental entities. This diversification limits our credit exposure to any one customer and potential cyclicality to any one industry. As a percentage of our 2015 revenues, the top ten industries we serviced totaled approximately 71% and included government (13%), chemical (12%), refineries and oil sands (11%), general manufacturing (9%), automotive (6%), base oil, blenders and packagers (6%), utilities (4%), oil gas production (4%), oil gas exploration (3%) and energy and consulting (3%).
- **Stable and Recurring Revenue Base**—We have long-standing relationships with our customers. Our diversified customer base also provides stable and recurring revenues as a majority of our revenues are derived from previously served customers with recurring needs for our services. In addition, switching costs for many of our customers are high. This is due to many customers' desire to audit disposal facilities prior to their qualification as approved sites and to limit the number of facilities to which their hazardous wastes are shipped in order to reduce their potential liability under United States and Canadian environmental regulations. We have been selected as an approved vendor by large and small generators of waste because we possess comprehensive collection, recycling, treatment, transportation, disposal, and waste tracking capabilities and have the expertise necessary to comply with applicable environmental laws and regulations. Those customers that have selected us as an approved vendor typically continue to use our services on a recurring basis.
- **Comprehensive Service Capabilities**—Our comprehensive service offerings allow us to act as a full-service provider to our customers. Our full-service orientation creates incremental revenue growth as customers seek to minimize the number of outside vendors and demand "one-stop shop" service providers.
- **Integrated Network of Assets**—We believe we operate, in the aggregate, the largest number of hazardous waste incinerators, landfills, treatment facilities and TSDFs in North America. Our broad service network enables us to effectively handle a waste stream from origin through disposal and to efficiently direct and internalize our waste streams to reduce costs. As our processing of wastes increases, our size allows us to increase our profit margins as we can internalize a greater volume of waste in our incinerators, landfills and other disposal facilities.
- **Regulatory Compliance**—We continue to make capital investments in our facilities to ensure that they are in compliance with current federal, state, provincial and local regulations. Companies that rely on in-house disposal may find the current regulatory requirements to be too capital intensive or complicated, and may choose to outsource many of their hazardous waste disposal needs.
- **Effective Cost Management**—Our significant scale allows us to maintain low costs through standardized compliance procedures, significant purchasing power, research and development capabilities and our ability to efficiently utilize logistics and transportation to economically direct waste streams to the most efficient facility. We also have the ability to transport and process with internal resources the substantial majority of all hazardous waste that we manage for our customers.
- **Proven and Experienced Management Team**—Our executive management team provides depth and continuity. Our 13 executive officers collectively have approximately 252 years of experience in the environmental, energy and industrial services industries. Our chief executive officer founded our Company in 1980, and the average experience of the 12 other members of the executive management team is approximately 18 years.

Operations

General

Seasonality and Cyclical Nature of Business. Our operations may be affected by seasonal fluctuations due to weather and budgetary cycles influencing the timing of customers' spending for remedial activities. Typically during the first quarter of each year there is less demand for environmental services due to the cold weather, particularly in the Northern and Midwestern United States and Canada. Accordingly, reduced volumes of waste are received at our facilities and higher operating costs are associated with operating in sub-freezing weather and high levels of snowfall. In addition, factory closings for the year-end holidays reduce the volume of industrial waste generated, which results in lower volumes of waste handled by us during the first quarter of the following year. In addition, our oil collection and recycling business may be affected by seasonal fluctuations due to weather cycles influencing the timing of customers' need for products and services. Typically during the first

quarter of each year there is less demand for our products and services due to the lower levels of activities by our customers as a result of the cold weather, particularly in the Northern and Midwestern regions of the United States and in Canada. This lower level of activity also results in lower volumes of used oil generated for collection by us in the first quarter.

Conversely, typically during the first quarter of each year there is more demand for our Industrial and Field Services and Oil and Gas Field Services segments due to the cold weather, particularly in Alberta, Canada, and less demand during the warmer months. The main reason for this is that the areas we service in Alberta are easier to access when the cold conditions make the terrain more suitable for companies to deploy their equipment. During the warmer months, thawing and muddy conditions may impede deployment of equipment.

Geographical Information. For the year ended December 31, 2015, we generated $2,576.2 million or 78.7% of our revenues in the United States and Puerto Rico, $695.0 million or 21.2% of revenues in Canada, and less than 1% of revenues in other international locations. For the year ended December 31, 2014, we generated $2,414.6 million or 71.0% of our revenues in the United States and Puerto Rico, $982.1 million or 28.9% of revenues in Canada, and less than 1% of revenues in other international locations. For additional information about the geographical areas from which our revenues are derived and in which our assets are located, see Note 17, "Segment Reporting," to our consolidated financial statements included in Item 8 of this report.

Technical Services

These services involve the collection, transportation, treatment and disposal of hazardous and non-hazardous wastes, and include resource recovery, physical treatment, fuels blending, incineration, landfill disposal, wastewater treatment, lab chemical disposal, explosives management, and CleanPack® services. Our CleanPack services include the collection, identification and categorization, specialized packaging, transportation and disposal of laboratory chemicals and household hazardous wastes. Our technical services are provided through a network of service centers from which a fleet of trucks are dispatched to pick up customers' wastes either on a predetermined schedule or on-demand, and to deliver the wastes to permitted facilities, which are usually Company-owned. Our service centers also can dispatch chemists to a customer location for the collection of chemical and laboratory waste for disposal.

Collection, Transportation and Logistics Management. As an integral part of our services, we collect industrial wastes from customers and transport such wastes to and between our facilities for treatment or bulking for shipment to final disposal locations. Customers typically accumulate wastes in containers, such as 55-gallon drums, bulk storage tanks or 20-cubic-yard roll-off containers. In providing this service, we utilize a variety of specially designed and constructed tank trucks and semi-trailers as well as third-party transporters, including railroads.

Treatment and Disposal. We recycle, treat and dispose of hazardous and non-hazardous industrial wastes. The wastes handled include substances which are classified as "hazardous" because of their corrosive, ignitable, infectious, reactive or toxic properties, and other substances subject to federal, state and provincial environmental regulation. We provide final treatment and disposal services designed to manage wastes which cannot be otherwise economically recycled or reused. The wastes we handle come in solid, sludge, liquid and gas form.

We operate a network of TSDFs that collect, temporarily store and/or consolidate compatible waste streams for more efficient transportation to final recycling, treatment or disposal destinations. These facilities hold special permits, such as Part B permits under the Resource Conservation and Recovery Act, or "RCRA," in the United States, which allow them to process waste through various technologies including recycling, incineration, and landfill and wastewater treatment.

Resource Recovery and Fuels Blending. We operate recycling systems for the reclamation and reuse of certain wastes, particularly solvent-based wastes generated by industrial cleaning operations, metal finishing and other manufacturing processes. Resource recovery involves the treatment of wastes using various methods, which effectively remove contaminants from the original material to restore its fitness for its intended purpose and to reduce the volume of waste requiring disposal.

We also operate a recycling facility that recycles refinery waste and spent catalyst. The recycled oil and recycled catalyst are sold to third parties.

Incineration. Incineration is the preferred method for the treatment of organic hazardous waste, because it effectively destroys the contaminants at high temperatures. High temperature incineration effectively eliminates organic wastes such as herbicides, halogenated solvents, pesticides, and pharmaceutical and refinery wastes, regardless of whether they are gases, liquids, sludge or solids. Federal and state incineration regulations require a destruction and removal efficiency of 99.99% for most organic wastes and 99.9999% for polychlorinated biphenyls, or "PCB," and dioxins.

As of December 31, 2015, we had eight active incinerators operating in five incineration facilities that offer a wide range of technological capabilities to customers through this network. In the United States, we operate a fluidized bed thermal

oxidation unit for maximum destruction efficiency of hazardous waste with an estimated annual capacity of 58,808 tons and three solids and liquids capable incineration facilities with a combined estimated annual capacity of 327,387 tons. We also operate one hazardous waste liquid injection incinerator in Canada with total annual capacity of 105,526 tons. Construction remains on schedule at our state-of-the-art hazardous waste incinerator at our El Dorado, Arkansas site. We expect this facility, the largest internal investment in Clean Harbors' history, to become commercially operational by year's end and to add approximately 70,000 tons of additional capacity.

Our incineration facilities in Kimball, Nebraska, Deer Park, Texas, El Dorado, Arkansas and Aragonite, Utah, are designed to process liquid organic wastes, sludge, solids, soil and debris. Our Deer Park facility has two kilns and a rotary reactor. Our El Dorado incineration facility specializes in the treatment of bulk and containerized hazardous liquids, solids and sludge through two rotary kilns. Our incineration facilities in Kimball and Deer Park have on-site landfills for the disposal of ash produced as a result of the incineration process.

Our incineration facilities in Lambton, Ontario are liquid injection incinerators, designed primarily for the destruction of liquid organic wastes. Typical waste streams include wastewater with low levels of organics and other higher concentration organic liquid wastes not amenable to conventional physical or chemical waste treatment.

Landfills. Landfills are primarily used for the disposal of inorganic wastes. In the United States and Canada, we operate nine commercial landfills. Seven of our commercial landfills are designed and permitted for the disposal of hazardous wastes and two of our landfills are operated for non-hazardous industrial waste disposal and, to a lesser extent, municipal solid waste. In addition to our commercial landfills, we also own and operate two non-commercial landfills that only accept waste from our on-site incinerators.

Of our seven commercial landfills used for disposal of hazardous waste, five are located in the United States and two are located in Canada. As of December 31, 2015, the useful economic lives of these landfills include approximately 24.9 million cubic yards of remaining capacity. This estimate of the useful economic lives of these landfills includes permitted airspace and unpermitted airspace that our management believes to be probable of being permitted based on our analysis of various factors. In addition to the capacity included in the useful economic lives of these landfills, there are approximately 31.9 million cubic yards of additional unpermitted airspace capacity included in the footprints of these landfills that may ultimately be permitted, although there can be no assurance that this unpermitted additional capacity will be permitted. In addition to the hazardous waste landfills, we operate two non-hazardous industrial landfills with 4.4 million cubic yards of remaining permitted capacity. These two facilities are located in the United States and have been issued operating permits under the authority of Subtitle D of RCRA. Our non-hazardous landfill facilities are permitted to accept commercial industrial waste, including wastes from foundries, demolition and construction, machine shops, automobile manufacturing, printing, metal fabrications and recycling.

Wastewater Treatment. We operate seven wastewater treatment facilities that offer a range of wastewater treatment technologies. These wastewater treatment operations involve processing hazardous and non-hazardous wastes through the use of physical and chemical treatment methods. These facilities treat a broad range of industrial liquid and semi-liquid wastes containing heavy metals, organics and suspended solids.

Industrial and Field Services

Industrial services include a wide range of industrial maintenance services and specialty industrial services provided at refineries, mines, upgraders, chemical plants, pulp and paper mills, manufacturing, and power generation facilities. We provide these services throughout North America, including a presence in the oil sands region in Alberta, Canada.

Our crews handle as-needed in-plant services to support ongoing in-plant cleaning and maintenance services, including liquid/dry vacuum, hydro-blasting, steam cleaning and chemical hauling. We provide a variety of specialized industrial services including plant outage and turnaround services, decoking and pigging, catalyst handling, chemical cleaning, high and ultra-high pressure water cleaning, and large tank and surface impoundment cleaning.

Field services provide customers with highly skilled experts who utilize specialty equipment and resources to perform services at any chosen location. Our field service crews and equipment are dispatched on a planned or emergency basis, and perform services such as confined space entry for tank cleaning, site decontamination, large remediation projects, demolition, spill cleanup, railcar cleaning, product recovery and transfer, scarifying and media blasting and vacuum services. Additional services include used oil and oil products recycling. Other services include filtration and water treatment services.

We are a leader in providing response services for environmental emergencies of any scale from man-made disasters, such as oil spills, and natural disasters such as hurricanes.

Kleen Performance Products

The used oil collected by the SK Environmental Services branch network is processed or re-refined to convert into a variety of products, mostly base lubricating oils, and much smaller quantities of asphalt-like material, glycols and fuels. As the largest re-refiner of used oil in the world, we process the used oil collected through our four re-refineries located in East Chicago, Indiana, Newark, California and Breslau, Ontario. Our recent acquisition on February 3, 2016 further expands our re-refinery network, with an additional facility located in Nevada. Our primary goal is to produce and sell high-quality blended oils, which are created by combining our re-refined base and other base oils with performance additives in accordance with our proprietary formulations and American Petroleum Institute licenses. Our Performance Plus brand, and our “green” proprietary brand, EcoPower, are sold to on and off-road corporate fleets, government entities, automotive service shops and industrial plants, which are serviced through our internal distribution network, as well as an extensive U.S. and Canada-wide independent distributor network. We also sell unbranded blended oils to distributors that resell them under their private label brands. The base oil we do not blend and sell ourselves is sold to independent blenders/packagers that use it to blend their own branded or private label oils. With more than 200 million gallons of used oil processed annually, we were able to return in 2015 approximately 160 million gallons of new re-refined oil, lubricants and byproducts back into the marketplace.

SK Environmental Services

Our Safety-Kleen service brand offers an array of environmental services and complementary products to a diverse range of customers including automobile repair shops, car and truck dealers, metal fabricators, machine manufacturers, fleet maintenance shops and other automotive, industrial and retail customers.

As the largest provider of parts cleaning services in North America, our Safety-Kleen operation offers a complete line of specially designed parts washers to customer locations and then delivers recurring service that includes machine cleaning and maintenance and the disposal and replacement of clean solvent or aqueous fluids. We performed more than 950,000 parts washer services in 2015. We also sell allied products including degreasers, glass and floor cleaners, hand cleaners, absorbents, antifreeze, windshield washer fluid, mats and spill kits.

Utilizing our collection network, we provide the pickup and transportation of hazardous and non-hazardous containerized waste for recycling or disposal, primarily through the Clean Harbors network of recycling and waste treatment and disposal facilities. Some of the collected waste consists of used oil which serves as feedstock for our oil re-refineries, although a portion of the used oil brought to the re-refineries is either not suitable for re-refining or cannot be re-refined because we do not have sufficient re-refining capacity at a specific point in time. That oil is processed into recycled fuel oil, or “RFO.” The RFO is then sold to various customers, such as asphalt plants, industrial plants, pulp and paper companies, and vacuum gas oil and marine diesel oil producers.

Our vacuum services provide the removal of solids, residual oily water and sludge and other fluids from customers' oil/water separators, sumps and collection tanks. We also remove and collect waste fluids found at large and small industrial locations, including metal fabricators, auto maintenance providers, and general manufacturers.

We provide total project management services in areas such as chemical packing, on-site waste management, remediation, compliance training and emergency spill response, while leveraging the Clean Harbors network of Technical, Industrial and Field Services centers and capabilities.

Lodging Services

Lodging Services consists of four lines of businesses; Lodge Operations, Mobile Camp Operations, Hospitality Operations, and Manufacturing. Synergy is created amongst all the lines of businesses within Lodging Services itself, as well with other Clean Harbors divisions by providing turnkey remote accommodations and manufacturing support.

Lodge Operations operates fixed lodges, ranging in size from 300 to 600 beds throughout Western Canada, primarily the Fort McMurray area. These include both client and open lodges, with amenities that include superior catering and housekeeping services, fully equipped common areas, fitness rooms and computer rooms, wireless internet and public phones, powered parking stalls, laundry facilities, and daily towel service.

Mobile Camp Operations include remote workforce accommodation facilities throughout Western Canada, currently in British Columbia, Saskatchewan and Alberta, with multiple accommodation types. These include both client and open camps, operator camps, and drill camps. Hospitality services are provided internally to the majority of the Lodges and Camps being operated, and include food services prepared by Red Seal Chefs, hospitality services, camp and lodge managers, and housekeeping. Furthermore, Hospitality services are available as a standalone service to clients who have other accommodation arrangements.

Manufacturing is provided through BCT Structures Inc. and Sanitherm Inc. BCT is a premier custom manufacturer of modular buildings specializing in providing workforce housing, office complexes, schools, lavatories, multi story buildings, affordable housing, kitchen facilities and other customized modular solutions for various industries. Sanitherm manufactures and operates water and wastewater treatment equipment and processes.

Oil and Gas Field Services

These services support exploration, drilling and production programs for oil and gas companies.

Seismic and Right-of-Way: On the exploration side, we provide integrated seismic and right-of-way services for efficient resource discovery and site preparation. These services include: (i) seismic surveying that minimizes costs, environmental impact, and time in field; (ii) mulching/line clearing that expedites additional geophysical activities and minimizes environmental impact; (iii) shot-hole drilling that provides safe and efficient operations in every terrain, including hostile and inaccessible regions; and (iv) borehole directional services that improve the efficient installation of pipeline, fiberoptic, cable, gas, water and sewer lines.

Surface Rentals: These services support oil and gas companies' drilling and well completion programs. Key to our services is our ability to provide solids control to support the drilling process. Our technologies help manage liquids, solids and semi-solid material during the drilling operation, and include centrifuges, tanks, and drilling fluid recovery. We also can provide container rentals for the safe collection of drill cuttings and other wastes, as well as manage disposal for drilling fluids and solids. We also supply surface rental equipment to support drill sites by providing wellsite trailers, wastewater treatment systems and holding tanks, light towers, and generators and handling tools.

Oilfield Transport and Production: These services support oil and gas companies drilling, completions and production programs. On the drilling and completions side, we provide vehicles and services for fluid hauling and disposal for ad hoc and turnkey operations. We also provide services and equipment for drilling site cleanups and support. On the production side, we provide complete turnarounds and tank cleaning services. Our downhole well equipment helps maintain and increase well productivity. Our other services include special chemical hauling, hydro-excavation, pressure/hydro testing equipment that tests pipelines and facilities, wellheads before operations startups, and rental production equipment for oil and gas well production.

Competition

The hazardous waste management industry in which we compete is highly competitive. The sources of competition vary by locality and by type of service rendered, with competition coming from national and regional waste services companies and hundreds of privately-owned firms. Veolia Environmental Services, or "Veolia," Waste Management, Inc., or "WM," and U.S. Ecology are the principal national firms with which we compete. Each of these competitors is able to provide one or more of the environmental services offered by us.

Under federal and state environmental laws in the United States, generators of hazardous wastes remain liable for improper disposal of such wastes. Although generators may hire various companies that have the proper permits and licenses, because of the generators' potential liability, they are very interested in the reputation and financial strength of the companies they use for the management of their hazardous wastes. We believe that our technical proficiency and reputation are important considerations to our customers in selecting and continuing to utilize our services.

We believe that the depth of our recycling, treatment and disposal capabilities and our ability to collect and transport waste products efficiently, quality of service, safety, and pricing are the most significant factors in the market for treatment and disposal services.

For our Technical Services segment, competitors include several major national and regional environmental services firms, as well as numerous smaller local firms. We believe the availability of skilled technical professional personnel, quality of performance, diversity of services and price are the key competitive factors in this service industry.

For our Industrial and Field Services segment, competitors vary by locality and by type of service rendered, with competition coming from national and regional service providers and hundreds of privately-owned firms that offer energy or industrial services. CEDA International Corporation and Newalta in Canada, and Philip Services Corporation, Hydrochem and Veolia in the United States, are the principal national firms with which we compete. Each of these competitors is able to provide one or more of the industrial and field services offered by us. We believe the availability of specialized equipment, skilled technical professional personnel, quality of performance, diversity of services and price are the key competitive factors in this industry.

For our Kleen Performance Products and SK Environmental Services segments, competitors vary by locality and by type of service rendered, with competition coming from Heritage Crystal Clean, and Veolia, along with several regional and local firms.

For our Lodging Services segment, competitors vary by locality and type of services provided. Our primary competitors in our lodging and remote camps business are Civeo, Black Diamond, Horizon North Logistics, Noralta, Royal Camps and William Scotsman, and in our manufacturing business, Atco Structures, Britco Manufacturing, Civeo, Horizon North Logistics and William Scotsman.

For our Oil and Gas Field Services segment, competitors vary by locality and type of service provided, with competition coming from national, regional and local service providers. Some of these competitors are able to provide one or more of the oil and gas services offered by us. Others only provide a limited range of equipment or services tailored for local markets. Competition is based on a number of factors, including safety, quality, performance, reliability, service, price, response time, and, in some cases, breadth of service offering.

The principal methods of competition for all of our services are price, quality, reliability of service rendered and technical proficiency. We believe that we offer a more comprehensive range of environmental, energy and industrial services than our competitors in major portions of our service territory.

Employees

As of December 31, 2015, we employed approximately 12,900 active full-time employees, of which 600 in the United States and 600 in Canada were represented by labor unions. We believe that our relationship with our employees is satisfactory. As part of our commitment to employee safety and quality customer service, we have an extensive compliance program and a trained environmental, health and safety staff. We adhere to a risk management program designed to reduce potential liabilities to us and to our customers.

Intellectual Property

We have invested significantly in the development of proprietary technology and also to establish and maintain an extensive knowledge of leading technologies and incorporate these technologies into the services we offer and provide to our customers. As of December 31, 2015, we held a total of 52 U.S. and 22 foreign issued or granted patents (which will expire between 2016 and 2031), 4 U.S. and 11 foreign pending patent applications, 70 U.S. and 52 foreign trademark registrations, and 13 U.S. and 11 foreign trademark applications. We also license software and other intellectual property from various third parties. We enter into confidentiality agreements with certain of our employees, consultants and corporate partners, and control access to software documentation and other proprietary information. We believe that we hold adequate rights to all intellectual property used in our business and that we do not infringe upon any intellectual property rights held by other parties.

Management of Risks

We adhere to a program of risk management policies and practices designed to reduce potential liability, as well as to manage customers' ongoing environmental exposures. This program includes installation of risk management systems at our facilities, such as fire suppression, employee training, environmental, auditing and policy decisions restricting the types of wastes handled. We evaluate all revenue opportunities and decline those that we believe involve unacceptable risks.

We dispose of wastes at our incineration, wastewater treatment and landfill facilities, or at facilities owned and operated by other firms that we have audited and approved. We apply established technologies to the treatment, storage and recovery of hazardous wastes. We believe our operations are conducted in a safe and prudent manner and in substantial compliance with applicable laws and regulations.

Insurance and Financial Assurance

Our insurance programs cover the potential risks associated with our multifaceted operations from two primary exposures: direct physical damage and third party liability. We maintain a casualty insurance program providing coverage for vehicles, employer's liability and commercial general liability in the aggregate amount of $105.0 million, $102.0 million and $104.0 million, respectively, per year, subject to retentions of $2.0 million per occurrence for auto and commercial general liability and $1.0 million for employers' liability in the United States and $2.0 million in Canada. We also have workers' compensation insurance whose limits are established by state statutes.

We have pollution liability insurance policies covering potential risks in three areas: as a contractor performing services at customer sites, as a transporter of waste and as a processor of waste at our facilities. The contractor's pollution liability insurance has limits of $20.0 million per occurrence and $25.0 million in the aggregate, covering offsite remedial activities and associated liabilities.

For sudden and accidental in-transit pollution liability, our auto liability policy provides the primary $5.0 million per occurrence of transportation pollution insurance. Our pollution liability policies provide an additional $60.0 million per occurrence and $85.0 million in the aggregate for a total of $65.0 million per occurrence and $90.0 million, respectively. A $2.0 million deductible per occurrence applies to this coverage in the United States and Canada.

Federal and state regulations require liability insurance coverage for all facilities that treat, store or dispose of hazardous waste. RCRA, the Toxic Substances Control Act, and comparable state hazardous waste regulations typically require hazardous waste handling facilities to maintain pollution liability insurance in the amount of $1.0 million per occurrence and $2.0 million in the aggregate for sudden occurrences, and $3.0 million per occurrence and $6.0 million in the aggregate for non-sudden occurrences. Our liability insurance coverage meets or exceeds all federal and state regulations.

Our international operations are insured under locally placed insurance policies that are compulsory to place in a specific country. In addition, we have a global foreign liability policy that will provide excess and difference in condition coverage in international countries.

Under our insurance programs, coverage is obtained for catastrophic exposures as well as those risks required to be insured by law or contract. It is our policy to retain a significant portion of certain expected losses related primarily to employee benefit, workers' compensation, commercial general and vehicle liability. Provisions for losses expected under these programs are recorded based upon our estimates of the actuarial calculation of the aggregate liability for claims. We believe that policy cancellation terms are similar to those of companies in other industries.

Operators of hazardous waste handling facilities are also required by federal, state and provincial regulations to provide financial assurance for closure and post-closure care of those facilities should the facilities cease operation. Closure would include the cost of removing the waste stored at a facility which ceased operating and sending the material to another facility for disposal and the cost of performing certain procedures for decontamination of the facility. As of December 31, 2015, our total estimated closure and post-closure costs requiring financial assurance by regulators were $429.5 million for our U.S. facilities and $38.9 million for our Canadian facilities. We have obtained all of the required financial assurance for our facilities through a combination of surety bonds, funded trusts, letters of credit and insurance from a qualified insurance company. The financial assurance related to closure and post-closure obligations of our U.S. facilities will renew in 2016. Our Canadian facilities utilize surety bonds, which renew at various dates throughout 2016, as well as letters of credit. In connection with obtaining such insurance and surety bonds, we have provided our insurance companies $81.8 million of letters of credit which we obtained from our lenders under our revolving credit agreement.

Environmental Regulation

While our business has benefited substantially from increased governmental regulation of hazardous waste transportation, storage and disposal, the environmental services industry itself is the subject of extensive and evolving regulation by federal, state, provincial and local authorities. We are required to obtain federal, state, provincial and local permits or approvals for each of our hazardous waste facilities. Such permits are difficult to obtain and, in many instances, extensive studies, tests, and public hearings are required before the approvals can be issued. We have acquired all operating permits and approvals now required for the current operation of our business, and have applied for, or are in the process of applying for, all permits and approvals needed in connection with continued operation and planned expansion or modifications of our operations.

We make a continuing effort to anticipate regulatory, political and legal developments that might affect operations, but are not always able to do so. We cannot predict the extent to which any environmental legislation or regulation that may be enacted or enforced in the future may affect our operations.

United States Hazardous Waste Regulation

Federal Regulations. The most significant federal environmental laws affecting us are the Resource Conservation and Recovery Act, or "RCRA," the Comprehensive Environmental Response, Compensation and Liability Act, or "CERCLA," also known as the "Superfund Act," the Clean Air Act, the Clean Water Act, and the Toxic Substances Control Act, or "TSCA."

RCRA. RCRA is the principal federal statute governing hazardous waste generation, treatment, transportation, storage and disposal. Pursuant to RCRA, the EPA has established a comprehensive "cradle-to-grave" system for the management of a wide range of materials identified as hazardous waste. States that have adopted hazardous waste management programs with standards at least as stringent as those promulgated by the EPA have been delegated authority by the EPA to administer their facility permitting programs in lieu of the EPA's program.

Every facility that treats, stores or disposes of hazardous waste must obtain a RCRA permit from the EPA or an authorized state agency unless a specific exemption exists, and must comply with certain operating requirements (the Part B permitting process). RCRA also requires that Part B permits contain provisions for required on-site study and cleanup activities,

known as "corrective action," including detailed compliance schedules and provisions for assurance of financial responsibility. See Note 8, "Closure and Post-Closure Liabilities," and Note 9, "Remedial Liabilities," to our consolidated financial statements included in Item 8 of this report for a discussion of our environmental liabilities. See "Insurance and Financial Assurance" above for a discussion of our financial assurance requirements.

The Superfund Act. The Superfund Act is the primary federal statute regulating the cleanup of inactive hazardous substance sites and imposing liability for cleanup on the responsible parties. It also provides for immediate response and removal actions coordinated by the EPA to releases of hazardous substances into the environment, and authorizes the government to respond to the release or threatened release of hazardous substances or to order responsible persons to perform any necessary cleanup. The statute provides for strict and, in certain cases, joint and several liability for these responses and other related costs, and for liability for the cost of damages to natural resources, to the parties involved in the generation, transportation and disposal of hazardous substances. Under the statute, we may be deemed liable as a generator or transporter of a hazardous substance which is released into the environment, or as the owner or operator of a facility from which there is a release of a hazardous substance into the environment. See Note 16, "Commitments and Contingencies," to our consolidated financial statements included in Item 8 of this report for a description of the principal such proceedings in which we are involved.

The Clean Air Act. The Clean Air Act was passed by Congress to control the emissions of pollutants into the air and requires permits to be obtained for certain sources of toxic air pollutants such as vinyl chloride, or criteria pollutants, such as carbon monoxide. In 1990, Congress amended the Clean Air Act to require further reductions of air pollutants with specific targets for non-attainment areas in order to meet certain ambient air quality standards. These amendments also require the EPA to promulgate regulations which (i) control emissions of 189 hazardous air pollutants; (ii) create uniform operating permits for major industrial facilities similar to RCRA operating permits; (iii) mandate the phase-out of ozone depleting chemicals; and (iv) provide for enhanced enforcement.

The Clean Water Act. This legislation prohibits discharge of pollutants into the waters of the United States without governmental authorization and regulates the discharge of pollutants into surface waters and sewers from a variety of sources, including disposal sites and treatment facilities. The EPA has promulgated "pretreatment" regulations under the Clean Water Act, which establish pretreatment standards for introduction of pollutants into publicly owned treatment works. In the course of the treatment process, our wastewater treatment facilities generate wastewater, which we discharge to publicly owned treatment works pursuant to permits issued by the appropriate governmental authority. We are required to obtain discharge permits and conduct sampling and monitoring programs. We believe each of our operating facilities complies in all material respects with the applicable requirements.

TSCA. We also operate a network of collection, treatment and field services (remediation) activities throughout North America that are regulated under provisions of TSCA. TSCA established a national program for the management of substances classified as polychlorinated biphenyls, or "PCBs," which include waste PCBs as well as RCRA wastes contaminated with PCBs. The rules set minimum design and operating requirements for storage, treatment and disposal of PCB wastes. Since their initial publication, the rules have been modified to enhance the management standards for TSCA-regulated operations including the decommissioning of PCB transformers and articles, detoxification of transformer oils, incineration of PCB liquids and solids, landfill disposal of PCB solids, and remediation of PCB contamination at customer sites.

Other Federal Laws. In addition to regulations specifically directed at the transportation, storage, and disposal facilities, there are a number of regulations that may "pass-through" to the facilities based on the acceptance of regulated waste from affected client facilities. Each facility that accepts affected waste must comply with the regulations for that waste, facility or industry. Examples of this type of regulation are National Emission Standards for Benzene Waste Operations and National Emissions Standards for Pharmaceuticals Production. Each of our facilities addresses these regulations on a case-by-case basis determined by its ability to comply with the pass-through regulations.

In our transportation operations, we are regulated by the U.S. Department of Transportation, the Federal Railroad Administration, the Federal Aviation Administration and the U.S. Coast Guard, as well as by the regulatory agencies of each state in which we operate or through which our vehicles pass.

Health and safety standards under the Occupational Safety and Health Act, or "OSHA," are also applicable to all of our operations.

State and Local Regulations. Pursuant to the EPA's authorization of their RCRA equivalent programs, a number of U.S. states have regulatory programs governing the operations and permitting of hazardous waste facilities. Accordingly, the hazardous waste treatment, storage and disposal activities of a number of our facilities are regulated by the relevant state agencies in addition to federal EPA regulation.

Some states classify as hazardous some wastes that are not regulated under RCRA. For example, Massachusetts considers used oil as "hazardous waste" while RCRA does not. Accordingly, we must comply with state requirements for handling state regulated wastes, and, when necessary, obtain state licenses for treating, storing, and disposing of such wastes at our facilities.

Our facilities are regulated pursuant to state statutes, including those addressing clean water and clean air. Local sewer discharge and flammable storage requirements are applicable to certain of our facilities. Our facilities are also subject to local siting, zoning and land use restrictions. We believe that each of our facilities is in substantial compliance with the applicable requirements of federal and state licenses which we have obtained pursuant thereto. Once issued, such licenses have maximum fixed terms of a given number of years, which differ from state to state, ranging from three to ten years. The issuing state agency may review or modify a license at any time during its term. We anticipate that once a license is issued with respect to a facility, the license will be renewed at the end of its term if the facility's operations are in compliance with applicable requirements. However, there can be no assurance that regulations governing future licensing will remain static, or that we will be able to comply with such requirements.

Canadian Hazardous Waste Regulation

In Canada, the provinces retain control over environmental issues within their boundaries and thus have the primary responsibility for regulating management of hazardous wastes. The federal government regulates issues of national scope or where activities cross provincial boundaries.

Provincial Regulations. Most of Canada's industrial development and the major part of its population are located in four provinces: Ontario, Quebec, Alberta and British Columbia. These provinces have the most detailed environmental regulations. We operate major waste management facilities in each of these provinces, as well as waste transfer facilities in Nova Scotia and Manitoba.

The main provincial acts dealing with hazardous waste management are:

- Ontario—Environmental Protection Act;
- Quebec—Environmental Quality Act;
- Alberta—Environmental Protection and Enhancement Act; and
- British Columbia—Waste Management Act.

These pieces of legislation were developed by the provinces independently and, among other things, generally control the generation, characterization, transport, treatment and disposal of hazardous wastes. Regulations developed by the provinces under the relevant legislation are also developed independently, but are often quite similar in effect and sometimes in application. For example, there is some uniformity in manifest design and utilization.

Provincial legislation also provides for the establishment of waste management facilities. In this case, the facilities are also controlled by provincial statutes and regulations governing emissions to air, groundwater and surface water and prescribing design criteria and operational guidelines.

Waste transporters require a permit to operate under provincial waste management regulations and are subject to the requirements of the Federal Transportation of Dangerous Goods legislation. They are required to report the quantities and disposition of materials shipped.

Canadian Federal Regulations. The Canadian federal government has authority for those matters which are national in scope and in impact and for Canada's relations with other nations. The main federal laws governing hazardous waste management are:

- Canadian Environmental Protection Act (1999) ("CEPA 99"), and
- Transportation of Dangerous Goods Act.

Environment Canada is the federal agency with responsibility for environmental matters and the main legislative instrument is the Canadian Environmental Protection Act. This act charges Environment Canada and Health Canada with protection of human health and the environment and seeks to control the production, importation and use of substances in Canada and to control their impact on the environment.

The Export and Import of Hazardous Wastes Regulations under CEPA 99 control the export and import of hazardous wastes and hazardous recyclable materials. By reference, these regulations incorporate the Transportation of Dangerous Goods Act and Regulations, which address identification, packaging, marking and documentation of hazardous materials during transport. CEPA 99 requires that anyone proposing to export or import hazardous wastes or hazardous recyclable materials or to

transport them through Canada notify the Minister of the Environment and obtain a permit to do so. Section 9 of CEPA 99 allows the federal government to enter into administrative agreements with the provinces and territories for the development and improvement of environmental standards. These agreements represent cooperation towards a common goal rather than a delegation of authority under CEPA 99. To facilitate the development of provincial and territorial agreements, the federal, provincial and territorial governments participate in the Canadian Council of Ministers of the Environment ("CCME"). The CCME comprises the 14 environment ministers from the federal, provincial and territorial governments, who normally meet twice a year to discuss national environmental priorities and to determine work to be carried out under the auspices of the CCME.

Canadian Local and Municipal Regulations. Local and municipal regulations seldom reference direct control of hazardous waste management activities. Municipal regulations and by-laws, however, control such issues as land use designation, access to municipal services and use of emergency services, all of which can have a significant impact on facility operation.

Compliance with Environmental Regulations

We incur costs and make capital investments in order to comply with the previously discussed environmental regulations. These regulations require that we remediate contaminated sites, operate our facilities in accordance with enacted regulations, obtain required financial assurance for closure and post-closure care of our facilities should such facilities cease operations, and make capital investments in order to keep our facilities in compliance with environmental regulations.

As further discussed in Note 8, "Closure and Post-Closure Liabilities," and Note 9, "Remedial Liabilities," to our consolidated financial statements included in Item 8 of this report, we have accrued environmental liabilities as of December 31, 2015, of $188.2 million. For the years ended December 31, 2015 and 2014, we spent $20.1 million and $20.2 million, respectively, to address environmental liabilities.

As discussed more fully above under the heading "Insurance and Financial Assurance," we are required to provide financial assurance with respect to certain statutorily required closure, post-closure and corrective action obligations at our facilities. We have placed the required financial assurance primarily through a qualified insurance company.

As described in Note 16, "Commitments and Contingencies," to our consolidated financial statements included in Item 8 of this report, we are involved in legal proceedings arising under environmental laws and regulations. Alleged failure to comply with laws and regulations may lead to the imposition of fines or the denial, revocation or delay of the renewal of permits and licenses by governmental entities. In addition, such governmental entities, as well as surrounding landowners, may claim that we are liable for environmental damages. Citizens groups have become increasingly active in challenging the grant or renewal of permits and licenses for hazardous waste facilities, and responding to such challenges has further increased the costs associated with establishing new facilities or expanding current facilities. A significant judgment against us, the loss of a significant permit or license, or the imposition of a significant fine could have a material effect on our business and future prospects.

ITEM 1A. RISK FACTORS

An investment in our securities involves certain risks, including those described below. You should consider carefully these risk factors together with all of the information included in this report before investing in our securities.

Risks Affecting All of Our Businesses

Our businesses are subject to operational and safety risks.

Provision of environmental, energy and industrial services to our customers by all six of our business segments involves risks such as equipment defects, malfunctions and failures, and natural disasters, which could potentially result in releases of hazardous materials, injury or death of our employees, or a need to shut down or reduce operation of our facilities while remedial actions are undertaken. Our employees often work under potentially hazardous conditions. These risks expose us to potential liability for pollution and other environmental damages, personal injury, loss of life, business interruption, and property damage or destruction. We must also maintain a solid safety record in order to remain a preferred supplier to our major customers.

While we seek to minimize our exposure to such risks through comprehensive training programs, vehicle and equipment maintenance programs, and insurance, such programs and insurance may not be adequate to cover all of our potential liabilities and such insurance may not in the future be available at commercially reasonable rates. If we were to incur substantial liabilities in excess of policy limits or at a time when we were not able to obtain adequate liability insurance on commercially reasonable terms, our business, results of operations and financial condition could be adversely affected to a material extent.

Furthermore, should our safety record deteriorate, we could be subject to a potential reduction of revenues from our major customers.

Our businesses are subject to numerous statutory and regulatory requirements, which may increase in the future.

Our businesses are subject to numerous statutory and regulatory requirements, and our ability to continue to hold licenses and permits required for our businesses is subject to maintaining satisfactory compliance with such requirements. These requirements may increase in the future as a result of statutory and regulatory changes. Although we are very committed to compliance and safety, we may not, either now or in the future, be in full compliance at all times with such statutory and regulatory requirements. Consequently, we could be required to incur significant costs to maintain or improve our compliance with such requirements.

Certain adverse conditions have required, and future conditions might require, us to make substantial write-downs in our assets, which have adversely affected or would adversely affect our balance sheet and results of operations.

We review our long-lived tangible and intangible assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable. We also test our goodwill and indefinite-lived intangible assets for impairment at least annually on December 31, or when events or changes in the business environment indicate that the carrying value of a reporting unit may exceed its fair value. Based on the results of those tests, we determined
during the second quarter of 2015 that the then carrying amount of our Oil and Gas Field Services reporting unit exceeded the estimated fair value of that unit and we therefore then recognized a goodwill impairment charge of $32.0 million with respect to that unit. During the third quarter of 2014, we determined that the then carrying amount of our Kleen Performance Products reporting unit exceeded the estimated fair value of that unit and we therefore then recognized a goodwill impairment charge of $123.4 million with respect to that unit. During and as of the end of each of 2015 and 2014, we determined that no other asset write-downs were required. However, if conditions in any of the businesses in which we compete were to deteriorate, we could determine that certain of our assets were impaired and we would then be required to write-off all or a portion of our costs for such assets. Any such significant write-offs would adversely affect our balance sheet and results of operations.

Fluctuations in foreign currency exchange could affect our financial results.

We earn revenues, pay expenses, own assets and incur liabilities in countries using currencies other than the U.S. dollar. In fiscal 2015, we recorded 21% of our revenues outside of the United States, primarily in Canada. Because our consolidated financial statements are presented in U.S. dollars, we must translate revenues, income and expenses as well as assets and liabilities into U.S. dollars at exchange rates in effect during or at the end of each reporting period. Therefore, increases or decreases in the value of the U.S. dollar against other currencies in countries where we operate will affect our results of operations and the value of balance sheet items denominated in foreign currencies. These risks are non-cash exposures, and we manage these risks through normal operating and financing activities. However, we may not be successful in reducing the risks inherent in exposures to foreign currency fluctuations.

Failure to effectively manage acquisitions and divestitures could adversely impact our future results.

We continuously evaluate potential acquisition candidates and from time to time acquire companies that we believe will strategically fit into our business and growth objectives. In particular, we acquired on December 28, 2012, all of the outstanding shares of Safety-Kleen for approximately $1.26 billion in cash, on September 13, 2013, all of the outstanding shares of Evergreen Oil, Inc. for approximately $56.3 million in cash, and on April 11, 2015, all of the outstanding shares of Thermo Fluids Inc. for approximately $78.6 million in cash, subject to customary closing conditions. If we are unable to successfully integrate and develop acquired businesses, we could fail to achieve anticipated synergies and cost savings, including any expected increases in revenues and operating results, which could have a material adverse effect on our financial results. We also continually review our portfolio of assets to determine the extent to which they are contributing to our objectives and growth strategy. In particular, on January 20, 2015, we announced a planned carve-out to include our Oil and Gas Field Service segment and the drilling-related mobile assets of our Lodging Services segment, subject to certain conditions, and on May 6, 2015, we announced the expansion of the planned carve-out to include our entire Lodging Services segment, subject to certain conditions. However, we may not be successful in separating underperforming or non-strategic assets, and gains or losses on the divestiture of, or lost operating income from, such assets may adversely affect our earnings. Moreover, we may incur asset impairment charges related to acquisitions or divestitures that reduce our earnings.

Our acquisitions may expose us to unknown liabilities.

Because we have acquired, and expect generally to acquire, all the outstanding shares of most of our acquired companies, our investment in those companies are or will be subject to all of their liabilities other than their respective debts which we paid or will pay at the time of the acquisitions. If there are unknown liabilities or other obligations, our business could be materially

affected. We may also experience issues relating to internal controls over financial reporting, issues that could affect our ability to comply with the Sarbanes-Oxley Act, or issues that could affect our ability to comply with other applicable laws.

A cyber security incident could negatively impact our business and our relationships with customers.

We use computers in substantially all aspects of our business operations and also mobile devices and other online activities to connect with our employees and customers. Such uses give rise to cyber security risks, including security breach, espionage, system disruption, theft and inadvertent release of information. Our business involves the storage and transmission of numerous classes of sensitive and/or confidential information and intellectual property including, but not limited to, private information about employees, and financial and strategic information about our Company and our business partners. Furthermore, as we pursue our strategy to grow through acquisitions and new initiatives that improve our operations and cost structure, we are also expanding and improving our information technologies, resulting in a larger technological presence and corresponding exposure to cyber security risk. If we fail to assess and identify cyber security risks associated with acquisitions and new initiatives, we may become increasingly vulnerable to such risks. Additionally, while we have implemented measures to prevent security breaches and cyber incidents, our preventative measures and incident response efforts may not be entirely effective. The theft, destruction, loss, misappropriation, or release of sensitive and/or confidential information or intellectual property, or interference with our information technology systems or the technology systems of third parties on which we rely, could result in business disruption, negative publicity, brand damage, violation of privacy laws, loss of customers, potential liability and competitive disadvantage.

Additional Risks of Our Technical Services Business

The hazardous waste management business conducted by our Technical Services segment is subject to significant environmental liabilities.

We have accrued environmental liabilities valued as of December 31, 2015, at $188.2 million, substantially all of which we assumed in connection with certain acquisitions. We calculate our environmental liabilities on a present value basis in accordance with generally accepted accounting principles, which take into consideration both the amount of such liabilities and the timing when it is projected that we will be required to pay such liabilities. We anticipate our environmental liabilities will be payable over many years and that cash flows generated from our operations will generally be sufficient to fund the payment of such liabilities when required. However, events not now anticipated (such as future changes in environmental laws and regulations or their enforcement) could require that such payments be made earlier or in greater amounts than now estimated, which could adversely affect our financial condition and results of operations.

We may also assume additional environmental liabilities as part of further acquisitions. Although we will endeavor to accurately estimate and limit environmental liabilities presented by the businesses or facilities to be acquired, some liabilities, including ones that may exist only because of the past operations of an acquired business or facility, may prove to be more difficult or costly to address than we then estimate. It is also possible that government officials responsible for enforcing environmental laws may believe an environmental liability is more significant than we then estimate, or that we will fail to identify or fully appreciate an existing liability before we become legally responsible to address it.

If we become unable to obtain at reasonable cost the insurance, surety bonds, letters of credit and other forms of financial assurance required for our facilities and operations, our business and results of operations would be adversely affected.

We are required to provide substantial amounts of financial assurance to governmental agencies for closure and post-closure care of our licensed hazardous waste treatment facilities should those facilities cease operation, and we are also occasionally required to post surety, bid and performance bonds in connection with certain projects. As of December 31, 2015, our total estimated closure and post-closure costs requiring financial assurance by regulators were $429.5 million for our U.S. facilities and $38.9 million for our Canadian facilities. We have obtained all of the required financial assurance for our facilities through a combination of surety bonds, funded trusts, letters of credit and insurance from a qualified insurance company. The financial assurance related to closure and post-closure obligations of our U.S. facilities will renew in 2016. Our Canadian facilities utilize surety bonds, which renew at various dates throughout 2016, as well as letters of credit. In connection with obtaining such insurance and surety bonds, we have provided our insurance companies $81.8 million of letters of credit which we obtained under our revolving credit agreement.

Our ability to continue operating our facilities and conducting our other operations would be adversely affected if we became unable to obtain sufficient insurance, surety bonds, letters of credit and other forms of financial assurance at reasonable cost to meet our regulatory and other business requirements. The availability of insurance, surety bonds, letters of credit and

other forms of financial assurance is affected by our insurers', sureties' and lenders' assessment of our risk and by other factors outside of our control such as general conditions in the insurance and credit markets.

The hazardous waste management industry in which we participate is subject to significant economic and business risks.

The future operating results of our Technical Services segment may be affected by such factors as our ability to utilize our facilities and workforce profitably in the face of intense price competition, maintain or increase market share in an industry which has in the past experienced significant downsizing and consolidation, realize benefits from cost reduction programs, invest in new technologies for treatment of hazardous waste, generate incremental volumes of waste to be handled through our facilities from existing and acquired sales offices and service centers, obtain sufficient volumes of waste at prices which produce revenue sufficient to offset the operating costs of our facilities, minimize downtime and disruptions of operations, and develop our field services business. In particular, economic downturns or recessionary conditions in North America, and increased outsourcing by North American manufacturers to plants located in countries with lower wage costs and less stringent environmental regulations, have adversely affected and may in the future adversely affect the demand for our services. Our Technical Services segment is also cyclical to the extent that it is dependent upon a stream of waste from cyclical industries such as chemical and petrochemical, primary metals, paper, furniture and aerospace. If those cyclical industries slow significantly, the business that we receive from them would likely decrease.

The extensive environmental regulations to which we are subject may increase our costs and potential liabilities and limit our ability to expand our facilities.

Our operations and those of others in the environmental services industry are subject to extensive federal, state, provincial and local environmental requirements in both the United States and Canada, including those relating to emissions to air, discharged wastewater, storage, treatment, transport and disposal of regulated materials, and cleanup of soil and groundwater contamination. For example, any failure to comply with governmental regulations governing the transport of hazardous materials could negatively impact our ability to collect, process and ultimately dispose of hazardous wastes generated by our customers. While increasing environmental regulation often presents new business opportunities for us, it often also results in increased operating and compliance costs. Efforts to conduct our operations in compliance with all applicable laws and regulations, including environmental rules and regulations, require programs to promote compliance, such as training employees and customers, purchasing health and safety equipment, and in some cases hiring outside consultants and lawyers. Even with these programs, we and other companies in the environmental services industry are routinely faced with governmental enforcement proceedings, which can result in fines or other sanctions and require expenditures for remedial work on waste management facilities and contaminated sites. Certain of these laws impose strict and, under certain circumstances, joint and several liability on current and former owners and operators of facilities that release regulated materials or that generate those materials and arrange for their disposal or treatment at contaminated sites. Such liabilities can relate to required cleanup of releases of regulated materials and related natural resource damages.

From time to time, we have paid fines or penalties in governmental environmental enforcement proceedings, usually involving our waste treatment, storage and disposal facilities. Although none of these fines or penalties that we have paid in the past has had a material adverse effect upon us, we might in the future be required to make substantial expenditures as a result of governmental proceedings which would have a negative impact on our earnings. Furthermore, regulators have the power to suspend or revoke permits or licenses needed for operation of our plants, equipment, and vehicles based on, among other factors, our compliance record, and customers may decide not to use a particular disposal facility or do business with us because of concerns about our compliance record. Suspension or revocation of permits or licenses would impact our operations and could have a material impact on our financial results. Although we have never had any of our facilities' operating permits revoked, suspended or non-renewed involuntarily, it is possible that such an event could occur in the future.

Some environmental laws and regulations impose liability and responsibility on present and former owners, operators or users of facilities and sites for contamination at such facilities and sites without regard to causation or knowledge of contamination. In the past, practices have resulted in releases of regulated materials at and from certain of our facilities, or the disposal of regulated materials at third party sites, which may require investigation and remediation, and potentially result in claims of personal injury, property damage and damages to natural resources. In addition, we occasionally evaluate various alternatives with respect to our facilities, including possible dispositions or closures. Investigations undertaken in connection with these activities may lead to discoveries of contamination that must be remediated, and closures of facilities might trigger compliance requirements that are not applicable to operating facilities. We are currently conducting remedial activities at certain of our facilities and paying a portion of the remediation costs at certain sites owned by third parties. While, based on available information, we do not believe these remedial activities will result in a material effect upon our operations or financial condition, these activities or the discovery of previously unknown conditions could result in material costs.

In addition to the costs of complying with environmental laws and regulations, we incur costs defending against environmental litigation brought by governmental agencies and private parties. We are now, and may in the future be, a defendant in lawsuits brought by parties alleging environmental damage, personal injury, and/or property damage, which may result in our payment of significant amounts of liabilities.

Environmental and land use laws also impact our ability to expand our facilities. In addition, we are required to obtain governmental permits to operate our facilities, including all of our landfills. Even if we comply with all applicable environmental laws, we might not be able to obtain requisite permits from applicable governmental authorities to extend or modify such permits to fit our business needs.

If our assumptions relating to expansion of our landfills should prove inaccurate, our results of operations and cash flow could be adversely affected.

When we include expansion airspace in our calculation of available airspace, we adjust our landfill liabilities to the present value of projected costs for cell closure and landfill closure and post-closure. It is possible that our estimates or assumptions could ultimately turn out to be significantly different from actual results. In some cases we may be unsuccessful in obtaining an expansion permit or we may determine that an expansion permit that we previously thought was probable has become unlikely. To the extent that such estimates, or the assumptions used to make those estimates, prove to be significantly different than actual results, or our belief that we will receive an expansion permit changes adversely in a significant manner, the landfill assets, including the assets incurred in the pursuit of the expansion, may be subject to impairment testing and lower prospective profitability may result due to increased interest accretion and depreciation or asset impairments related to the removal of previously included expansion airspace. In addition, if our assumptions concerning expansion airspace should prove inaccurate, certain of our cash expenditures for closure of landfills could be accelerated and adversely affect our results of operations and cash flow.

Additional Risks of Our Industrial and Field Services Business

A significant portion of our Industrial and Field Services business depends upon the demand for cleanup of major spills and other remedial projects and regulatory developments over which we have no control.

Our operations can be affected by the commencement and completion of cleanup of major spills and other events, customers' decisions to undertake remedial projects, seasonal fluctuations due to weather and budgetary cycles influencing the timing of customers' spending for remedial activities, the timing of regulatory decisions relating to hazardous waste management projects, changes in regulations governing the management of hazardous waste, secular changes in the waste processing industry towards waste minimization and the propensity for delays in the demand for remedial services, and changes in the myriad of governmental regulations governing our diverse operations. We do not control such factors and, as a result, our revenue and income can vary from quarter to quarter, and past financial performance for certain quarters may not be a reliable indicator of future performance for comparable quarters in subsequent years.

Additional Risks of Our Kleen Performance Products Business

Fluctuations in oil prices may have a negative effect on our Kleen Performance Products business.

A significant portion of our business involves collecting used oil from certain of our customers, re-refining a portion of such used oil into base and blended lubricating oils, and then selling both such re-refined oil and the excess recycled oil which we do not currently have the capacity to re-refine, or ‘‘RFO,’’ to other customers. The prices at which we sell our re-refined oil and RFO are affected by changes in the reported spot market prices of oil. If applicable rates increase or decrease, we typically will charge a higher or lower corresponding price for our re-refined oil and RFO. The price at which we sell our re-refined oil and RFO is affected by changes in certain indices measuring changes in the price of heavy fuel oil, with increases and decreases in the indices typically translating into a higher or lower price for our RFO. The cost to collect used oil, including the amounts we pay to obtain a portion of our used oil and therefore ability to collect necessary volumes as well as the fuel costs of our oil collection fleet, typically also increases or decreases when the relevant indices increase or decrease. However, even though the prices we can charge for our re-refined oil and RFO and the costs to collect and re-refine used oil and process RFO typically increase and decrease together, there is no assurance that when our costs to collect and re-refine used oil and process RFO increase we will be able to increase the prices we charge for our re-refined oil and RFO to cover such increased costs, or that our costs to collect and re-refine used oil and process RFO will decline when the prices we can charge for re-refined oil and RFO decline. These risks are exacerbated when there are rapid fluctuations in these oil indices.

Additional Risks of Our SK Environmental Services Business

Environmental laws and regulations have adversely affected and may adversely affect Safety-Kleen's parts cleaning and other solvent related services.

In connection with its parts cleaning and other solvent related services, Safety-Kleen has been subject to fines and certain orders requiring it to take environmental remedial action. Safety-Kleen may be subject to monetary fines, civil or criminal penalties, remediation, cleanup or stop orders, injunctions, orders to cease or suspend certain practices or denial of permits required for the operation of its facilities. The outcome of any proceeding and associated costs and expenses could have a material adverse impact on Safety-Kleen’s financial condition and results of operations.

Recent and potential changes in environmental laws and regulations may also adversely affect in the future Safety-Kleen's parts cleaning and other solvent related services. Interpretation or enforcement of existing laws and regulations, or the adoption of new laws and regulations, may require Safety-Kleen to modify or curtail its operations or replace or upgrade its facilities or equipment at substantial cost, which we may not be able to pass on to our customers, and we may choose to indemnify our customers from any fines or penalties they may incur as a result of these new laws and regulations. On the other hand, in some cases if new laws and regulations are less stringent, Safety-Kleen’s customers or competitors may be able to manage waste more effectively themselves, which could decrease the need for Safety-Kleen’s services or increase competition, which could adversely affect Safety-Kleen’s results of operations.

Safety-Kleen is subject to existing and potential product liability lawsuits.

Safety-Kleen has been named from time to time as a defendant in various product liability lawsuits in various courts and jurisdictions throughout the United States. As of December 31, 2015, Safety-Kleen was involved in approximately 58 proceedings (including cases which have been settled but not formally dismissed) wherein persons claim personal injury resulting from the use of its parts cleaning equipment or cleaning products. These proceedings typically involve allegations that the solvent used in Safety-Kleen’s parts cleaning equipment contains contaminants or that Safety-Kleen’s recycling process does not effectively remove the contaminants that become entrained in the solvent during their use. In addition, certain claimants assert that Safety-Kleen failed to warn adequately the product user of potential risks, including a historic failure to warn that solvent contains trace amounts of toxic or hazardous substances such as benzene. Although Safety-Kleen maintains insurance that we believe will provide coverage for these claims (over amounts accrued for self-insured retentions and deductibles in certain limited cases), this insurance may not provide coverage for potential awards of punitive damages against Safety-Kleen. Although Safety-Kleen has vigorously defended and will continue to vigorously defend itself and the safety of its products against all of these claims, these matters are subject to many uncertainties and outcomes are not predictable with assurance. Safety-Kleen may also be named in similar, additional lawsuits in the future, including claims for which insurance coverage may not be available. If one or more of these claims were decided unfavorably against Safety-Kleen and the plaintiffs were awarded punitive damages, or if insurance coverage were not available for any such claim, our financial condition and results of operations could be materially and adversely affected. Additionally, if one or more of these claims were decided unfavorably against Safety-Kleen, such outcome may encourage more lawsuits against us.

Safety-Kleen is dependent on third parties for the manufacturing of the majority of its equipment.

Safety-Kleen does not manufacture the majority of the equipment, including parts washers, that Safety-Kleen places at customer sites. Accordingly, Safety-Kleen relies on a limited number of third party suppliers for manufacturing this equipment. The supply of third party equipment could be interrupted or halted by a termination of Safety-Kleen’s relationships, a failure of quality control or other operational problems at such suppliers or a significant decline in their financial condition. If Safety-Kleen were not able to retain these providers or obtain its requests from them, Safety-Kleen may not be able to obtain alternate providers in a timely manner or on economically attractive terms, and as a result, Safety-Kleen may not be able to compete successfully for new business, complete existing engagements profitably or retain its existing customers. Additionally, if Safety-Kleen’s third party suppliers provide it with defective equipment, it may be subject to reputational damage or product liability claims which may negatively impact its reputation, financial condition and results of operations. Further, Safety-Kleen generally does not have long-term contracts with its third party suppliers, and as a result these suppliers may increase the price of the equipment they provide to Safety-Kleen, which may hurt Safety-Kleen’s results of operations.

Additional Risks of Our Lodging Services Business

All of our major Canadian lodges are located on land subject to leases; if we were unable to renew a lease, we could be materially and adversely affected.

All of our major Canadian lodges are located on land subject to leases. Accordingly, while we own the accommodations assets and can move them to other locations, if necessary, we only own a leasehold in those properties. If we were found to be in breach of a lease, we could lose the right to use the property. In addition, unless we could extend the terms of these leases before their expiration, we would lose our right to operate our facilities located on these properties upon expiration of the leases. In that event, we would be required to remove our accommodations assets and remediate the sites. We may not be able to renew our leases upon expiration on similar terms, or at all, and if we were unable to renew leases on similar terms, it may have an adverse effect on our business. In addition, if we were to lose the right to use a lodge due to non-renewal of a lease, we would be unable to derive income from such lodge, which could materially and adversely affect us.

Due to the significant concentration of our Lodging Services business in the oil sands region of Alberta, Canada, adverse events in that region could negatively impact our business.

Because of the concentration of our accommodations business in the oil sands region of Alberta, Canada, we have increased exposure to political, economic, regulatory, environmental, labor, climate or natural disaster events or developments that could disproportionately impact our operations and financial results.

Our Lodging Services business depends significantly on several major customers, and the loss of one or more such customers or the inability of one or more such customers to meet their obligations to us could adversely affect our results of operations.

Our Lodging Services business depends significantly on several major customers engaged primarily in oil and gas exploration and production. Declines in the general level of oil and gas exploration and production in the oil sands region resulting in decreased demand in our lodging services have occured in recent periods and could occur in the future, and have had and could have in the future adverse effects on the revenues and profitability of our Lodging Services business. The loss of any one or more of such large customers or a sustained decrease in demand by any of them have resulted and could result in a substantial loss of revenues and have had and could have a material adverse effect on our results of operations. In addition, the concentration of our customers in oil and gas exploration and production may impact our overall exposure to credit risk, either positively or negatively, because our customers may be similarly affected by changes in economic and industry conditions. While we perform ongoing credit evaluations of our customers, we do not generally require collateral in support of our trade receivables. As a result, we are subject to risks of loss resulting from nonpayment or nonperformance by our customers.

We may be adversely affected if customers reduce their accommodations outsourcing.

The business and growth strategy of our Lodging Services business depends in large part on the continuation of a current trend toward outsourcing services. Many oil and gas companies in our core markets own their own accommodations facilities, while others outsource all or part of their accommodations requirements. Customers have largely built their accommodations in the past but will outsource if they perceive that outsourcing may provide quality services at a lower overall cost or allow them to accelerate the timing of their projects. We cannot be certain that this trend will continue and not be reversed or that customers that have outsourced accommodations will not decide to perform these functions themselves or only outsource accommodations during the development or construction phases of their projects. In addition, labor unions representing customer employees and contractors have, in the past, opposed outsourcing accommodations to the extent that the unions believe that third-party accommodations negatively impact union membership and recruiting. The reversal or reduction in customer outsourcing of accommodations could negatively impact our financial results and growth prospects.

Increased operating costs and obstacles to cost recovery due to the pricing and cancellation terms of our accommodation services contracts may constrain our ability to make a profit.

The profitability of our Lodging Services business can be adversely affected by cost increases for food, wages and other labor related expenses, insurance, fuel and utilities, especially to the extent we are unable to recover such increased costs through increases in the prices for our services due to general economic conditions, competitive conditions or contractual provisions in our customer contracts. Oil and natural gas prices have fluctuated significantly in the last several years, and substantial increases in the cost of fuel and utilities have historically resulted in cost increases for our lodges. From time to time we have also experienced increases in our food costs. While we believe a portion of these increases were attributable to fuel prices, we believe the increases also resulted from rising global food demand. In addition, food prices can fluctuate as a result

of temporary changes in supply, including as a result of severe weather such as droughts, heavy rains and late freezes. While our long term contracts often provide for annual escalation in our room rates for food, labor and utility inflation, we may be unable to fully recover costs and such increases in costs would negatively impact our profitability on contracts that do not contain inflation protections.

Additional Risks of Our Oil and Gas Field Services Business

A large portion of our Oil and Gas Field Services business is dependent on the oil and gas industry in Western Canada, and declines in oil and gas exploration and production in that region have adversely affected and could in the future adversely affect our business.

Our Oil and Gas Field Services business generates a significant portion of its total revenues from customers in the oil and gas industry operating in Western Canada, although a majority of the services we provide to such customers relate to oil and gas production and refining which is less volatile than oil and gas exploration. Accordingly, declines in the general level of oil and gas exploration and production in Western Canada have had and could potentially have significant adverse effects on the revenues and profitability of our Oil and Gas Field Services business and have resulted and could also potentially result in asset impairment charges being recognized, including the goodwill impairment charge of $32.0 million we recognized with respect to our Oil and Gas Field Services reporting unit during the third quarter of 2015. Such declines have occurred and could potentially occur in the future if reductions in the commodity prices of oil and gas result in reduced oil and gas exploration, production and refining. Such declines could also be triggered by technological and regulatory changes, such as those affecting the availability and cost of alternative energy sources and other changes in industry and worldwide economic and political conditions.

Many of our major customers in the oil and gas industry conduct a significant portion of their operations in the Alberta oil sands. The Alberta oil sands contain large oil deposits, but extraction may involve significantly greater cost and environmental concerns than conventional drilling. While we believe our major involvement in the oil sands region will provide significant future growth opportunities, such involvement also increases the risk that our business will be adversely affected if future economic activity in the Alberta oil sands were to further decline. Major factors that could cause such a decline might include a prolonged reduction in the commodity price of oil, future changes in environmental restrictions and regulations, and technological and regulatory changes relating to production of oil from the oil sands. The downturn in worldwide economic conditions and in the commodity price of oil and gas which has recently occurred and continues to occur has caused certain of our customers to delay a number of large projects in the planning and early development phases within the oil sands region. In addition, customers are revisiting their operating budgets and challenging their suppliers to reduce costs and achieve better efficiencies in their work programs.

Although we plan to carve-out our Oil and Gas Field Services and Lodging Services segments into a stand-alone new public company, there is no assurance if and when such carve-out will occur. Furthermore, even if and when such carve-out does occur, we will remain subject to the risks now associated with our Oil and Gas Field Services and Lodging Services segments as long as we retain a significant ownership interest in such new public company.

On January 20, 2015, we announced that we plan to carve out primarily our Oil and Gas Field Services segment and our lodging drill camps business from our Lodging Services segment into a new standalone public company. On May 6, 2015, we expanded the planned carve-out to include our entire Lodging Services segment as part of that new company. Timing could take more than 12 months and completion of the carve-out is subject to certain conditions including, but not limited to, market conditions, determination of the most advantageous structure from a financial and tax standpoint, overall costs to our Company, receipt of regulatory approvals, compliance with our debt covenants, the effectiveness of securities laws filings and final approval by our board of directors. There can be no assurance regarding the ultimate structure and timing of the proposed transaction or whether the transaction will be completed. Furthermore, even if and when such carve-out does occur, we will remain subject to the risks now associated with our Oil and Gas Field Services and Lodging Services segments as long as we retain a significant ownership interest in the new public company.

Risks Relating to Our Level of Debt, Letters of Credit and Senior Unsecured Notes

Our substantial levels of outstanding debt and letters of credit could adversely affect our financial condition and ability to fulfill our obligations.

As of December 31, 2015, we had outstanding $1.4 billion of senior unsecured notes and $144.6 million of letters of credit. Our substantial levels of outstanding debt and letters of credit may:

- adversely impact our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or other general corporate purposes or to repurchase the notes from holders upon any change of control;

- require us to dedicate a substantial portion of our cash flow to the payment of interest on our debt and fees on our letters of credit, which reduces the availability of our cash flow to fund working capital, capital expenditures, acquisitions and other general corporate purposes;
- subject us to the risk of increased sensitivity to interest rate increases based upon variable interest rates, including borrowings (if any) under our revolving credit facility;
- increase the possibility of an event of default under the financial and operating covenants contained in our debt instruments; and
- limit our ability to adjust to rapidly changing market conditions, reduce our ability to withstand competitive pressures and make us more vulnerable to a downturn in general economic conditions of our business than our competitors with less debt.

Our ability to make scheduled payments of principal or interest with respect to our debt, including our outstanding notes, any revolving loans and our capital leases, and to pay fee obligations with respect to our letters of credit, will depend on our ability to generate cash and on our future financial results. If we were unable to generate sufficient cash flow from operations in the future to service our debt and letter of credit fee obligations, we might be required to refinance all or a portion of our existing debt and letter of credit facilities or to obtain new or additional such facilities. However, we might not be able to obtain any such new or additional facilities on favorable terms or at all.

Despite our substantial levels of outstanding debt and letters of credit, we could incur substantially more debt and letter of credit obligations in the future.

Although our revolving credit agreement and the indentures governing our outstanding notes contain restrictions on the incurrence of additional indebtedness (including, for this purpose, reimbursement obligations under outstanding letters of credit), these restrictions are subject to a number of qualifications and exceptions and the additional indebtedness which we might incur in the future in compliance with these restrictions could be substantial. In particular, we had available at December 31, 2015, up to an additional approximately $178.5 million for purposes of additional borrowings and letters of credit. The revolving credit agreement and the indentures governing our outstanding notes also allow us to borrow significant amounts of money from other sources. These restrictions would also not prevent us from incurring obligations (such as operating leases) that do not constitute “indebtedness” as defined in the relevant agreements. To the extent we incur in the future additional debt and letter of credit obligations, the related risks would increase.

The covenants in our debt agreements restrict our ability to operate our business and might lead to a default under our debt agreements.

Our revolving credit agreement and the indentures governing our outstanding notes limit, among other things, our ability and the ability of our restricted subsidiaries to:

- incur or guarantee additional indebtedness (including, for this purpose, reimbursement obligations under letters of credit) or issue preferred stock;
- pay dividends or make other distributions to our stockholders;
- purchase or redeem capital stock or subordinated indebtedness;
- make investments;
- create liens;
- incur restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to us;
- sell assets, including capital stock of our subsidiaries;
- consolidate or merge with or into other companies or transfer all or substantially all of our assets; and
- engage in transactions with affiliates.

As a result of these covenants, we may not be able to respond to changes in business and economic conditions and to obtain additional financing, if needed, and we may be prevented from engaging in transactions that might otherwise be beneficial to us. Our revolving credit facility requires, and our future credit facilities may require, us to maintain certain financial ratios and satisfy certain other financial condition tests. Our ability to meet these financial ratios and tests can be affected by events beyond our control, and we may not be able to meet those tests. The breach of any of these covenants could result in a default under our revolving credit facility or future credit facilities. Upon the occurrence of an event of default, the lenders could elect to declare all amounts outstanding under such credit facilities, including accrued interest or other obligations, to be immediately due and payable. If amounts outstanding under such credit facilities were to be accelerated, our assets might not be sufficient to repay in full that indebtedness and our other indebtedness.

Our revolving credit agreement and the indentures governing our outstanding notes also contain cross-default and cross-acceleration provisions. Under these provisions, a default or acceleration under one instrument governing our debt may constitute a default under our other debt instruments that contain cross-default and cross-acceleration provisions, which could result in the related debt and the debt issued under such other instruments becoming immediately due and payable. In such event, we would need to raise funds from alternative sources, which funds might not be available to us on favorable terms, on a timely basis or at all. Alternatively, such a default could require us to sell assets and otherwise curtail operations to pay our creditors. The proceeds of such a sale of assets, or curtailment of operations, might not enable us to pay all of our liabilities.

Other Risks Relating to Our Common Stock

The Massachusetts Business Corporation Act and our By-Laws contain certain anti-takeover provisions.

Sections 8.06 and 7.02 of the Massachusetts Business Corporation Act provide that Massachusetts corporations which are publicly-held must have a staggered board of directors and that written demand by holders of at least 40% of the outstanding shares of each relevant voting group of stockholders is required for stockholders to call a special meeting unless such corporations take certain actions to affirmatively "opt-out" of such requirements. In accordance with these provisions, our By-Laws provide for a staggered Board of Directors which consists of three classes of directors of which one class is elected each year for a three-year term, and require that written application by holders of at least 25% (which is less than the 40% which would otherwise be applicable without such a specific provision in our By-Laws) of our outstanding shares of common stock is required for stockholders to call a special meeting. In addition, our By-Laws prohibit the removal by the stockholders of a director except for cause. These provisions could inhibit a takeover of our Company by restricting stockholders' action to replace the existing directors or approve other actions which a party seeking to acquire us might propose. A takeover transaction would frequently afford stockholders an opportunity to sell their shares at a premium over then market prices.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Our principal executive offices are in Norwell, Massachusetts where approximately 151,000 square feet is leased under arrangements expiring in 2022. There are also regional administrative offices in Texas, South Carolina and Alberta, Canada. Our properties are sufficient and suitable for our current needs.

We have a network of more than 450 service locations across 47 states, eight Canadian provinces, Puerto Rico, Mexico, and Trinidad. Those service locations include service centers, satellite locations, branches, active hazardous waste management properties, lodging facilities and oil processing facilities. The service centers and branches are the principal sales and service centers from which we provide our environmental, energy and industrial services. The active hazardous waste management properties include incineration facilities, commercial and non-commercial landfills, wastewater treatment facilities, treatment, storage and disposal facilities ("TSDFs"), solvent recovery management and recycling facilities, locations specializing in polychlorinated biphenyls ("PCBs") management, oil accumulation centers, oil terminals and oil re-refineries. Some of our properties offer multiple capabilities. The following sets forth certain information as of December 31, 2015 regarding our properties. Our principal owned operating properties located in the United States are mortgaged as collateral under our revolving credit facility.

Service Centers, Satellite Locations and Branches

We have approximately 330 service centers, satellite locations and branches throughout the United States and Canada which serve as principal sales and service centers from which we provide parts cleaning services, containerized waste services, oil collection services and other environmental services.

Active Hazardous Waste Management Properties

Incineration Facilities. We own five operating incineration facilities that have a total of eight incinerators with 491,721 tons of total practical capacity and an average utilization rate for 2015 of 90.9%. The Company's practical capacity is not based on a theoretical 24-hour, seven-day operation, but rather is determined as the production level at which the incinerator can operate with an acceptable degree of efficiency, taking into consideration factors such as longer term customer demand, permanent staffing levels, operating shifts, holidays, scheduled maintenance and mix of product. Capacity utilization is calculated by dividing actual production pounds by practical capacity at each incinerator.

	# of Incinerators	Practical Capacity (Tons)	Utilization Rate Year Ended December 31, 2015
Arkansas	2	95,072	80.5%
Nebraska	1	58,808	79.2%
Utah	1	66,815	83.0%
Texas	3	165,500	94.6%
Ontario, Canada	1	105,526	105.9%
	8	491,721	90.9%

Our incinerators offer a wide range of technological capabilities to customers through this network. Incineration in the United States is provided by one fluidized bed thermal oxidation unit and three solids and liquids-capable incineration facilities and in Canada, we operate one active hazardous waste liquid injection incinerator. In addition, construction remains on schedule at our state-of-the-art hazardous waste incinerator at our El Dorado, Arkansas site. We expect this facility, the largest internal investment in Clean Harbors' history, to become commercially operational by year's end and to add approximately 70,000 tons of additional capacity.

Commercial and Non-Commercial Landfills. In the United States and Canada, we operate nine commercial landfills with approximately 29.3 million cubic yards of remaining highly probable airspace. Seven of our commercial landfills are designed and permitted for the disposal of hazardous wastes and two landfills are operated for nonhazardous industrial waste disposal and, to a lesser extent, municipal solid waste. In addition to our commercial landfills, we also own and operate two non-commercial landfills that only accept waste from our on-site incinerators. See "Landfill Accounting" within Note 2, "Significant Accounting Policies," to our consolidated financial statements included in Item 8 of this report for additional information on our commercial and non-commercial landfills.

Wastewater Treatment Facilities. We operate a total of seven facilities, of which five are owned and two are leased, that offer a range of wastewater treatment technologies and customer services. Wastewater treatment consists primarily of three types of services: hazardous wastewater treatment, sludge de-watering or drying, and non-hazardous wastewater treatment.

Treatment, Storage and Disposal Facilities. We operate 22 TSDFs, of which 20 are owned and two are leased, in the United States and Canada. Our TSDFs facilitate the movement of materials among our network of service centers and treatment and disposal facilities. Transportation may be accomplished by truck, rail, barge or a combination of modes, with our own assets or in conjunction with third-party transporters. Specially designed containment systems, vehicles and other equipment permitted for hazardous and industrial waste transport, together with drivers trained in transportation and waste handling procedures, provide for the movement of customer waste streams.

Solvent Recovery Management and Recycling Operations. We own two facilities specializing in solvent recovery management.

PCB Management Facilities and Oil Storage or Recycling Capabilities. We operate nine facilities, of which seven are owned and two are leased, specializing in PCB management or providing oil recycling capabilities.

Lodging Facilities

Lodge Operations. We operate seven fixed lodges, all of which are owned and located on sites in Alberta, Canada that are leased under long term operating agreements.

Camps. We operate various camp facilities that can grow and shrink in size and location. Generally, we have ongoing operations at 2-4 larger facilities that we expect to operate on a multi-year basis. Additionally, in our fleet we can operate five office complexes, six mini-camps, and approximately 50 single and double occupancy drill camps. All of our camp facilities are owned and located on various sites throughout Western Canada. Sites for the larger facilities are generally leased, whereas sites for the smaller facilities are generally provided by our customers.

Oil Processing Facilities

Oil Accumulation Centers. We operate a total of nine accumulation centers, of which eight are owned and one is leased, used for accumulating waste oil from our branches.

Oil Terminals. We operate a total of 56 oil terminals, of which 25 are owned and 31 are leased, which collect or process used oil prior to delivery to re-refineries or distribution as RFO.

Oil Recycling and Re-refining Facilities. With our recent acquisition we now own four oil re-refineries, three in the United States and one in Canada. With more than 200 million gallons of used oil processed annually, we were able to return in 2015 over 160 million gallons of new re-refined oil, lubricants and byproducts back into the marketplace.

ITEM 3. LEGAL PROCEEDINGS

See Note 16, "Commitments and Contingencies," to our consolidated financial statements included in Item 8 of this report for a description of legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Common Stock

Our common stock trades on the New York Stock Exchange (the "NYSE") under the symbol CLH. The following table sets forth the high and low sales prices of our common stock for the indicated periods as reported by the NYSE.

	2015		2014	
	High	Low	High	Low
First Quarter	$ 58.44	$ 44.70	$ 60.47	$ 44.95
Second Quarter	$ 59.29	$ 50.65	$ 64.30	$ 52.02
Third Quarter	$ 54.31	$ 43.00	$ 65.53	$ 53.66
Fourth Quarter	$ 48.05	$ 39.89	$ 53.84	$ 43.05

On February 19, 2016, the closing price of our common stock on the NYSE was $42.53 and there were 301 stockholders of record of our common stock, excluding stockholders whose shares were held in nominee, or "street," name. We estimate that approximately 24,800 additional stockholders beneficially held shares in street name on that date.

We have never declared nor paid any cash dividends on our common stock, and we do not intend to pay any dividends on our common stock in the foreseeable future. We intend to retain our future earnings, if any, for use in the operation and expansion of our business, payment of our outstanding debt and our stock repurchase program. In addition, our current credit agreement and indentures limit the amount we could pay as cash dividends on, or for repurchase of, our common stock. See "Liquidity and Capital Resources" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share (2)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (3)
October 1, 2015 through October 31, 2015	78,903	$ 45.07	78,398	$ 122,311,562
November 1, 2015 through November 30, 2015	421	$ 46.49	—	$ 122,311,562
December 1, 2015 through December 31, 2015	2,161	$ 41.44	—	$ 122,311,562
Total	81,485	$ 44.98	78,398	$ 122,311,562

(1) Includes 3,087 shares withheld by us from employees to satisfy employee tax obligations upon vesting of restricted stock units granted to our employees under our long-term equity incentive programs.
(2) The average price paid per share of common stock repurchased under our stock repurchase program includes the commissions paid to the brokers.
(3) On March 13, 2015, our board of directors increased the size of our current share repurchase program from up to $150 million to up to $300 million. We intend to fund the repurchases through available cash resources. The stock repurchase program authorizes us to purchase our common stock on the open market from time to time. The stock repurchases will be made in a manner that complies with applicable U.S. securities laws. The number of shares purchased and the timing of the purchases will depend on a number of factors, including share price, cash required for future business plans, trading volume and other conditions. We have no obligation to repurchase stock under this program and may suspend or terminate the repurchase program at any time.

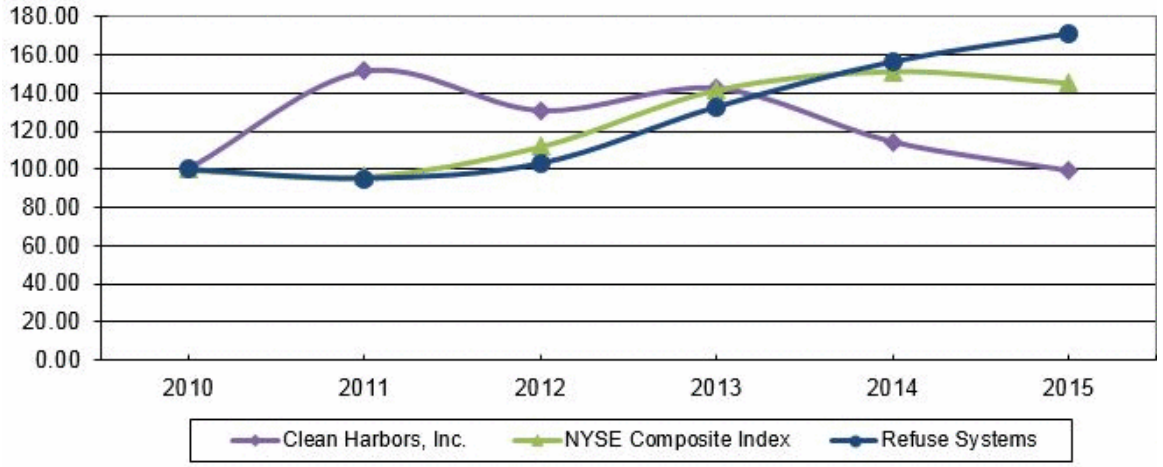
COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN

AMONG CLEAN HARBORS, INC.,

NYSE COMPOSITE INDEX, AND CUSTOM PEER GROUP

Performance Graph

The following graph compares the five-year return from investing $100 in each of our common stock, the NYSE Composite Index, and an index of environmental services companies (custom peer group) compiled by CoreData. The environmental services group used by CoreData includes all companies whose listed line-of-business is SIC Code 4953 (refuse systems), and assumes reinvestment of dividends on the ex-dividend date. An index compares relative performance since a particular starting date. In this instance, the starting date was December 31, 2010, when our common stock closed at $42.04 per share.



ASSUMES $100 INVESTED ON JAN. 01, 2010

ASSUMES DIVIDEND REINVESTED

Securities Authorized For Issuance Under Equity Compensation Plans

See Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters," for a description of the securities which are authorized for issuance under our equity compensation plans.

ITEM 6. SELECTED FINANCIAL DATA

The following summary of consolidated financial information has been derived from the audited consolidated financial statements included in Item 8, "Financial Statements and Supplementary Data," of this report and in the annual reports we previously filed with the SEC. This information should be reviewed in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and the financial statements and the notes thereto included in Item 8, "Financial Statements and Supplementary Data," of this report.

	For the Year Ended December 31,				
(in thousands except per share amounts)	2015	2014	2013	2012	2011
Income Statement Data:					
Total revenues	$ 3,275,137	$ 3,401,636	$ 3,509,656	$ 2,187,908	$ 1,984,136
Net income (loss) (1)	$ 44,102	$ (28,328)	$ 95,566	$ 129,674	$ 127,252
Earnings (loss) per share: (1)(2)					
Basic	$ 0.76	$ (0.47)	$ 1.58	$ 2.41	$ 2.40
Diluted	$ 0.76	$ (0.47)	$ 1.57	$ 2.40	$ 2.39
Other Financial Data:					
Adjusted EBITDA (3)	$ 504,167	$ 521,919	$ 510,105	$ 373,767	$ 350,008

	At December 31,				
(in thousands)	2015	2014	2013	2012	2011
Balance Sheet Data:					
Total assets (4)	$ 3,431,428	$ 3,689,423	$ 3,936,430	$ 3,819,338	$ 2,076,089
Long-term obligations (including current portion) (4)	1,382,543	1,380,681	1,385,516	1,389,223	529,174
Stockholders' equity (2)	1,096,282	1,262,871	1,475,639	1,432,072	900,987

(1) The 2015 results include a $32.0 million goodwill impairment charge in our Oil and Gas Field Services reporting unit and the 2014 results include a $123.4 million goodwill impairment charge in our Kleen Performance Products reporting unit. In 2015 and 2014, we recorded an income tax benefit of $2.0 million and $2.7 million, respectively, as a result of the goodwill impairment charge. See Note 6, "Goodwill and Other Intangible Assets," to our consolidated financial statements included in Item 8 of this report for additional information regarding those goodwill impairment charges. The 2012 results include a $26.4 million loss on early extinguishment of debt in connection with a redemption and repurchase of our $520.0 million previously outstanding senior secured notes and a benefit for income taxes of $1.9 million primarily due to a decrease in unrecognized tax benefits of $52.4 million (net of interest and penalties of $29.3 million) resulting from expiring statute of limitation periods related to a historical Canadian debt restructuring transaction.

(2) We issued 6.9 million shares of our common stock in December 2012 upon the closing of a public offering for aggregate net proceeds of $369.3 million.

(3) See "Adjusted EBITDA" under Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this report for a discussion of Adjusted EBITDA.

(4) As a result of the adoption of a new accounting pronouncement issued in 2015 and discussed further in Note 2 under item 8, "Financial Statements and Supplementary Data" under the heading *Recent Accounting Pronouncements*, total assets and long-term obligations previously reported in prior period financial statements have been reclassified in accordance with the adopted pronouncements.

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

Overview

We are North America's leading provider of environmental, energy and industrial services. We serve a diverse customer base, including a majority of the Fortune 500, across the chemical, energy, manufacturing and additional markets, as well as numerous government agencies. These customers rely on us to deliver a broad range of services including but not limited to end-to-end hazardous waste management, emergency spill response, industrial cleaning and maintenance, and recycling services. Through our acquisition in December 2012 of Safety-Kleen, Inc. ("Safety-Kleen"), we are also the largest re-refiner and recycler of used oil in the world and the largest provider of parts cleaning and environmental services to commercial, industrial and automotive customers in North America. On April 11, 2015, we acquired Thermo Fluids Inc. ("TFI") for an estimated preliminary acquisition price of approximately $78.6 million. Results of this business are included in the SK Environmental Services segment.

Performance of our segments is evaluated on several factors of which the primary financial measure is Adjusted EBITDA as described more fully below. The following is a discussion of how management evaluates its segments in regards to other factors including key performance indicators that management uses to assess the segments' results as well as certain macroeconomic trends and influences that impact each reportable segment:

- **Technical Services -** Technical Services segment results are predicated upon the demand by our customers for waste services directly attributable to waste volumes generated by them and the existence of project work contracted by the Technical Services segment and/or other segments of Clean Harbors whereby waste handling and/or disposal is required. In managing the business and evaluating performance, management tracks the volumes of waste handled and disposed of through our owned incinerators and landfills as well as the utilization of such incinerators. Levels of activity and ultimate performance associated with this segment can be impacted by inherent seasonality in the business and weather conditions, market conditions and overall levels of industrial activity, efficiency of our operations, competition and market pricing of our services and the management of our related operating costs.

- **Industrial and Field Services -** Industrial and Field Services segment results are impacted by the demand for planned and unplanned industrial related cleaning and maintenance services at customer sites and the requirement for environmental cleanup services on a scheduled or emergency basis, including response to national events such as major oil spills, natural disasters or other events where immediate and specialized services are pertinent. Management considers the number of plant sites where services are contracted and expected site turnaround schedules to be indicators of the businesses' performance along with the existence of local or national events.

- **Kleen Performance Products -** Kleen Performance Products results are significantly impacted by the overall market pricing and product mix associated with base and blended oil products and more specifically the published prices of Group II base oils, which historically have seen correlation with overall crude oil prices which experienced significant declines for much of 2014 and into 2015. Costs associated with used oils, which are raw materials associated with the segment's products, can also be volatile as was the case for much of 2014 and into 2015 when such costs were disconnected from market pricing of the based and blended oil products sold by the segment. Given the impact of these falling prices, we are now charging disposal rates in order to mitigate the market-derived pressure on our margins and avoid further deterioration in the existing spread.

- **SK Environmental Services -** SK Environmental Services segment results are significantly impacted by the number of parts washers serviced by the business and the ability to attract small quantity waste producers as customers and integrate them into the Clean Harbors waste network. Performance is also predicated upon the segment management's ability to manage related costs associated with transportation and the servicing of customers and successfully managing costs associated with the collection of used oils which are then transferred to the Kleen Performance Products segment.

- **Lodging Services -** Lodging Services segment results are dependent upon levels of construction and maintenance activity associated with the oil and related industries in the Oil Sands and other regions of Western Canada in which our camps and lodges operate and demand for our modular unit production. Levels of overall activity in these regions drive the demand and related pricing for lodging and camp accommodations and related services. To mitigate the decrease in demand experienced in this business we have targeted more non-traditional markets such as schools and hospitals to offer our modular unit accommodations and related services. Given that segment

operations are located entirely in Canada the impact of foreign currency translations which result from changes in the exchange rates between the U.S. and Canadian dollar can significantly impact the amounts associated with overall business results.

- **Oil and Gas Field Services -** Oil and Gas Field Services segment results are significantly impacted by overall levels of oil and gas related exploration, drilling activity and production in North America. The levels of such exploration, drilling activity and production are largely dependent upon the number of oil rigs in operation as well as global and North American oil prices on which such activity levels are strongly predicated. Since the third quarter of 2014 crude oil prices have declined approximately 62%. This recent oil price volatility and future price uncertainty has resulted in lower activity levels which are negatively impacting the business' results. The majority of the segment's operations are in Canada, and therefore the impacts of US to Canadian dollar foreign currency translation also significantly impacts the segment's results.

Highlights

Total revenues for 2015 decreased 3.7% to $3.28 billion from $3.40 billion in 2014. Decreases in total revenue were primarily attributable to lower revenues in those segments most impacted by the low oil price environment which existed in 2015, along with corresponding decreases in base oil prices. Our Kleen Performance Products, Oil and Gas Field Services and Lodging Services segments were significantly and negatively impacted by lower oil prices in 2015. The results in these segments were partially offset by significant revenues earned by the Industrial and Field Services segment from emergency response projects and increased U.S. industrial turnaround activity which occurred in 2015. The weakening Canadian dollar and related effects of foreign currency translation on our Canadian business operations also negatively impacted direct revenues by approximately $108.3 million in 2015 as compared to 2014. Changes in segment revenues are more fully described in our Segment Performance section below.

We reported income from operations in 2015 of $187.6 million compared with $111.8 million in 2014. Income from operations in 2015 included a $32.0 million goodwill impairment charge recorded on our Oil and Gas Field Services reporting unit, while income from operations in 2014 included a $123.4 million goodwill impairment charge recorded on our Kleen Performance Products reporting unit. Adjusted EBITDA, which is the primary financial measure by which our segments are evaluated, decreased 3.4% to $504.2 million for 2015 from $521.9 million for 2014. Additional information, including a reconciliation of Adjusted EBITDA to net income (loss), appears below under the heading *"Adjusted EBITDA."*

Segment Performance

Performance of our segments is evaluated on several factors of which the primary financial measure is Adjusted EBITDA. The following table sets forth certain operating data associated with our results of operations for the years ended December 31, 2015, 2014 and 2013.

	Summary of Operations (in thousands)						
	Year Ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Third Party Revenues[1]:							
Technical Services	$ 991,410	$ 1,043,267	$ 1,023,926	$ (51,857)	(5.0)%	$ 19,341	1.9 %
Industrial and Field Services	957,337	681,779	708,523	275,558	40.4	(26,744)	(3.8)
Kleen Performance Products	386,824	533,587	528,636	(146,763)	(27.5)	4,951	100.0
SK Environmental Services	674,102	667,320	665,008	6,782	1.0	2,312	100.0
Lodging Services	89,060	172,218	208,545	(83,158)	(48.3)	(36,327)	(17.4)
Oil and Gas Field Services	175,946	303,189	383,959	(127,243)	(42.0)	(80,770)	(21.0)
Corporate Items[2]	458	276	(8,941)	182	(65.9)	9,217	(103.1)
Total	$ 3,275,137	$ 3,401,636	$ 3,509,656	$ (126,499)	(3.7)%	$ (108,020)	(3.1)%
Direct Revenues[1]:							
Technical Services	$ 1,139,080	$ 1,205,383	$ 1,147,815	$ (66,303)	(5.5)%	$ 57,568	5.0 %
Industrial and Field Services	923,599	639,369	663,589	284,230	44.5	(24,220)	(3.6)
Kleen Performance Products	306,825	331,723	335,627	(24,898)	(7.5)	(3,904)	(1.2)
SK Environmental Services	634,864	747,739	772,099	(112,875)	(15.1)	(24,360)	(3.2)
Lodging Services	91,713	174,732	212,385	(83,019)	(47.5)	(37,653)	(17.7)
Oil and Gas Field Services	181,780	308,270	390,505	(126,490)	(41.0)	(82,235)	(21.1)
Corporate Items[2]	(2,724)	(5,580)	(12,364)	2,856	51.2	6,784	54.9
Total	3,275,137	3,401,636	3,509,656	(126,499)	(3.7)	(108,020)	(3.1)
Cost of Revenues[3]:							
Technical Services	769,625	791,824	779,472	(22,199)	(2.8)	12,352	1.6
Industrial and Field Services	706,093	499,423	513,519	206,670	41.4	(14,096)	(2.7)
Kleen Performance Products	258,653	264,437	259,905	(5,784)	(2.2)	4,532	100.0
SK Environmental Services	390,664	524,280	551,129	(133,616)	(25.5)	(26,849)	100.0
Lodging Services	70,331	108,066	127,259	(37,735)	(34.9)	(19,193)	(15.1)
Oil and Gas Field Services	160,840	244,642	295,659	(83,802)	(34.3)	(51,017)	(17.3)
Corporate Items[2]	600	9,124	15,690	(8,524)	(93.4)	(6,566)	(41.8)
Total	2,356,806	2,441,796	2,542,633	(84,990)	(3.5)	(100,837)	(4.0)
Selling, General and Administrative Expenses:							
Technical Services	77,718	85,429	82,823	(7,711)	(9.0)	2,606	3.1
Industrial and Field Services	60,006	52,355	53,266	7,651	14.6	(911)	(1.7)
Kleen Performance Products	15,983	15,725	18,719	258	1.6	(2,994)	100.0
SK Environmental Services	104,127	109,473	108,248	(5,346)	(4.9)	1,225	100.0
Lodging Services	4,904	5,228	4,768	(324)	(6.2)	460	9.6
Oil and Gas Field Services	21,767	23,514	26,991	(1,747)	(7.4)	(3,477)	(12.9)
Corporate Items	129,659	146,197	175,662	(16,538)	(11.3)	(29,465)	(16.8)
Total	414,164	437,921	470,477	(23,757)	(5.4)	(32,556)	(6.9)
Adjusted EBITDA							
Technical Services	291,737	328,130	285,520	(36,393)	(11.1)	42,610	14.9
Industrial and Field Services	157,500	87,591	96,804	69,909	79.8	(9,213)	(9.5)
Kleen Performance Products	32,189	51,561	57,003	(19,372)	(37.6)	(5,442)	100.0
SK Environmental Services	140,073	113,986	112,722	26,087	22.9	1,264	100.0
Lodging Services	16,478	61,438	80,358	(44,960)	(73.2)	(18,920)	(23.5)
Oil and Gas Field Services	(827)	40,114	67,855	(40,941)	(102.1)	(27,741)	(40.9)
Corporate Items	(132,983)	(160,901)	(190,157)	27,918	17.4	29,256	15.4
Total	$ 504,167	$ 521,919	$ 510,105	$ (17,752)	(3.4)%	$ 11,814	2.3 %

(1) Third party revenue is revenue billed to outside customers by a particular segment. Direct revenue is revenue allocated to the segment performing the provided service.
(2) Corporate Items revenues and costs of revenues for the year ended December 31, 2013 includes purchase price measurement period adjustments.
(3) Cost of revenue is shown exclusive of items presented separately on the statements of income, which consist of (i) accretion of environmental liabilities and (ii) depreciation and amortization.

Direct Revenues

There are many factors which have impacted, and continue to impact, our revenues. These factors include, but are not limited to: foreign currency translation, acquisitions, general conditions of the oil and gas related industries, competitive industry pricing, the effects of fuel prices on our fuel recovery fees, and the level of emergency response projects.

Technical Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Direct revenues	$ 1,139,080	$ 1,205,383	$ 1,147,815	$ (66,303)	(5.5)%	$ 57,568	5.0%

Technical Services direct revenues for the year ended December 31, 2015 decreased 5.5%, or $66.3 million, from the comparable period in 2014 primarily due to decreased revenues associated with our waste disposal services whereby waste is disposed of through our incinerator and landfill facilities network. This direct revenue decrease was impacted by lower waste volumes disposed of in our landfills, which decreased 28.6% primarily due to lower oil and gas production waste streams and project delays. Pricing attributable to our recycled products and fuel recovery revenues were also negatively impacted from overall lower market rates. The utilization rate at our incinerators was 90.9% for year ended December 31, 2015, respectively, compared with 91.2% in the comparable period of 2014.

Direct revenues for the year ended December 31, 2014 increased 5.0% or $57.6 million, from the comparable period in 2013 primarily due to increased revenues associated with our waste disposal services whereby waste is disposed of through our incinerator and landfill facilities network. This direct revenue increase was primarily due to higher waste volumes disposed of in our landfills, which increased 10.0%. In 2014, we made several upgrades and enhancements to our Canada incinerator increasing its practical capacity by approximately 12,000 tons. The utilization rate at our incinerators was 91.2% for the year ended December 31, 2014, compared with 89.2% in the comparable period of 2013.

Industrial and Field Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Direct revenues	$ 923,599	$ 639,369	$ 663,589	$ 284,230	44.5%	$ (24,220)	(3.6)%

Industrial and Field Services direct revenues for the year ended December 31, 2015 increased 44.5%, or $284.2 million, from the comparable period in 2014. The increase was primarily due to revenues associated with our Field Services business, which included emergency response service projects that took place during 2015 and accounted for approximately $306.6 million of incremental revenues for the year ended December 31, 2015. The significant level of emergency response projects responded to during 2015 included services primarily in response to outbreaks of the avian flu and oil spill related incidents. In addition, for the year ended December 31, 2015, U.S. industrial turnaround activity primarily at refineries increased $13.4 million from the comparable period in 2014. This increase was offset primarily by lower revenue amounts generated from industrial services work performed in the Oil Sands region of Canada. Lower activity levels in this region reduced customer maintenance and projects, which negatively impacted our revenues by $40.0 million in the year ended December 31, 2015, from the comparable period in 2014. Inclusive in the year over year changes within this segment were also the negative impacts of foreign currency translation on our Canadian operations of approximately $31.8 million as a result of the weakening Canadian dollar in the year ended December 31, 2015 from the comparable period in 2014.

Direct revenues for the year ended December 31, 2014 decreased 3.6%, or $24.2 million, from the comparable period in 2013, primarily due to decreasing global oil prices which were a catalyst to lower levels of activity in 2014. These lower activity levels in 2014 accounted for decreases and postponements of plant turnaround services which, combined with the natural cyclicality of such planned turnaround activity, amounted to $20.5 million of decreased revenues as compared to the comparable period of 2013. Inclusive in the year over year changes within this segment were also the negative impacts of foreign currency translation on our Canadian operations of approximately $12.9 million as a result of the weakening Canadian dollar in the year ended December 31, 2014 from the comparable period in 2013.

Kleen Performance Products

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Direct revenues	$ 306,825	$ 331,723	$ 335,627	$ (24,898)	(7.5)%	$ (3,904)	(1.2)%

Kleen Performance Products direct revenues represent third party revenues, which are earned on sales to external customers, reduced by intersegment revenues consisting of amounts paid to the SK Environmental Services segment for used oil collections, which are then further processed in manufacturing base and blended oil products sold by this segment. Direct revenues attributable to the Kleen Performance Products segment decreased 7.5%, or $24.9 million, from the comparable period in 2014. Decreases in base and blended oil volumes and decreases in pricing of oil products both had negative impacts on direct revenues in the year ended December 31, 2015. Lower volumes accounted for $20.4 million from the comparable period in 2014, with lower pricing accounting for $134.1 million from the comparable period of 2014. These negative impacts to revenues were partially offset by the lower levels of intersegment revenue related to lower reimbursement to the SK Environmental segment for used oil. As compared to the comparable period in 2014, intersegment revenues were reduced by $121.9 million during the year ended December 31, 2015. Inclusive in the year over year changes within this segment were also the negative impacts of foreign currency translation on our Canadian operations of approximately $13.2 million as a result of the weakening Canadian dollar in the year ended December 31, 2015 from the comparable period in 2014.

Direct revenues for the year ended December 31, 2014 decreased 1.2%, or $3.9 million, from the comparable period in 2013. Decreases in base and blended oil pricing, as well as an increase in intersegment revenue primarily related to higher reimbursement to the SK Environmental segment for used oil, both had negative impacts on direct revenues in the year ended December 31, 2014. As compared to the comparable period in 2013, lower pricing accounted for $18.8 million and intersegment revenue accounted for $8.9 million of the reduced revenue during the year ended December 31, 2014. These negative impacts to revenues were offset by increased overall volumes primarily resulting from a full years operation of the refinery acquired in our acquisition of Evergreen on September 13, 2013. The increased volumes accounted for $27.3 million of additional revenue in 2014. Inclusive in the year over year changes within this segment were also the negative impacts of foreign currency translation on our Canadian operations of approximately $4.0 million as a result of the weakening Canadian dollar in the year ended December 31, 2014 from the comparable period in 2013.

SK Environmental Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Direct revenues	$ 634,864	$ 747,739	$ 772,099	$ (112,875)	(15.1)%	$ (24,360)	(3.2)%

SK Environmental Services direct revenues include intersegment revenues earned from the sale of used oil collections to the Kleen Performance Products segment. SK Environmental Services direct revenues for the year ended December 31, 2015 decreased 15.1%, or $112.9 million, from the comparable period in 2014. This decrease was the result of expected reductions in intersegment revenues related to the sale of used oil to the Kleen Performance Products segment in the amount of approximately $153.1 million due to successful management in our pay-for-oil program. This decrease in intersegment amounts impacting direct revenues were offset in the year ended December 31, 2015 by additional revenues from the TFI acquisition of $34.4 million and increases of other services primarily related to containerized waste, Allied products and parts washers for the year ended December 31, 2015 from the comparable period in 2014.

Direct revenues for the year ended December 31, 2014 decreased 3.2%, or $24.4 million, from the comparable period in 2013. This decrease was primarily due to system integration changes which occurred in May of 2013 and changed the manner by which waste is tracked across our disposal network.

Lodging Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Direct revenues	$ 91,713	$ 174,732	$ 212,385	$ (83,019)	(47.5)%	$ (37,653)	(17.7)%

Lodging Services direct revenues for the year ended December 31, 2015 decreased 47.5%, or $83.0 million, from the comparable period in 2014 primarily due to decreases in the occupancy rates at our lodges resulting from overall lower activity in oil related industries in Western Canada. Occupancy rates at our primary fixed lodges for the year ended December 31, 2015 were 33%, compared to 61% in the comparable period in 2014. The decrease in demand also negatively impacted pricing consistent with overall market conditions which combined resulted in decreases in direct revenue of $57.8 million for the year ended December 31, 2015 from the comparable period in 2014. Direct revenues derived from our camps and catering services also decreased $15.0 million in the year ended December 31, 2015 from the comparable period in 2014. Manufacturing revenues decreased during the year ended December 31, 2015 by $9.4 million from the comparable period in 2014 due to a large project which occurred in 2014. Inclusive in the year over year changes within this segment were also the negative impacts of foreign currency translation on our Canadian operations of approximately $14.2 million as a result of the weakening Canadian dollar in the year ended December 31, 2015 from the comparable period in 2014.

Direct revenues for the year ended December 31, 2014 decreased 17.7%, or $37.7 million, from the comparable period in 2013 primarily due to a slow down in overall market activity in the oil sands region and other areas of Western Canada where the majority of this segment operates and therefore decreased demand for our Lodging Services. The decrease in overall market demand also negatively impacted pricing, which combined with the decrease in demand, resulted in decreases in direct revenue of $16.2 million for the year ended December 31, 2014 from the comparable period in 2013. Direct revenues derived from our camps and catering services also decreased $12.2 million in the year ended December 31, 2014 from the comparable period in 2013. Manufacturing revenues decreased during the year ended December 31, 2014 by $10.0 million from the comparable period in 2013. Inclusive in the year over year changes within this segment were also the negative impacts of foreign currency translation on our Canadian operations of approximately $9.1 million as a result of the weakening Canadian dollar in the year ended December 31, 2014 from the comparable period in 2013.

Oil and Gas Field Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Direct revenues	$ 181,780	$ 308,270	$ 390,505	$ (126,490)	(41.0)%	$ (82,235)	(21.1)%

Oil and Gas Field Services direct revenues for the year ended December 31, 2015 decreased 41.0%, or $126.5 million, from the comparable period in 2014 primarily due to lower levels of activity and rig counts serviced by the businesses which negatively impacted the utilization and overall pricing of our rental equipment and productions services assets. Rig count serviced by the Oil and Gas Field Services segment decreased approximately 32% in the year ended December 31, 2015 from the comparable period in 2014. Project cancellations and lower exploration budgets of our customers decreased overall activity levels in the marketplace, which also negatively impacted results in 2015. Inclusive in the year over year changes within this segment were also the negative impacts of foreign currency translation on our Canadian operations of approximately $19.6 million as a result of the weakening Canadian dollar in the year ended December 31, 2015 from the comparable period in 2014.

Direct revenues for the year ended December 31, 2014 decreased 21.1%, or $82.2 million, from the comparable period in 2013 primarily due to lower levels of activity and project delays in our exploration and production services of approximately $80.1 million related to event and project related work which occurred in 2013 and did not reoccur in 2014. The lower levels of overall activity in the Oil and Gas exploration markets which existed during 2014 were attributed to the volatility and resulting uncertainties experienced in oil pricing which, led to reductions in our customers' and the industries' operating budgets. Inclusive in the year over year changes within this segment were also the negative impacts of foreign currency translation on our Canadian operations of approximately $11.7 million as a result of the weakening Canadian dollar in the year ended December 31, 2014 from the comparable period in 2013.

Cost of Revenues

We believe that our ability to manage operating costs is important to our ability to remain price competitive. We continue to upgrade the quality and efficiency of our services through the development of new technology and continued modifications at our facilities, and implementation of strategic sourcing and other cost reduction initiatives in an effort to improve our operating margins.

Technical Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Cost of revenues	$ 769,625	$ 791,824	$ 779,472	$ (22,199)	(2.8)%	$ 12,352	1.6 %
As a % of Direct Revenue	67.6%	65.7%	67.9%		1.9 %		(2.2)%

Technical Services cost of revenues for the year ended December 31, 2015 decreased 2.8%, or $22.2 million, from the comparable period in 2014 due to decreases in fuel expense of $13.2 million and transportation of $9.3 million. As a percentage of revenues, our costs increased 1.9% for the year ended December 31, 2015 as compared to 2014, primarily due to lower revenue levels associated with higher margin businesses such as landfills in 2015.

Cost of revenues for the year ended December 31, 2014 increased 1.6%, or $12.4 million, from the comparable period in 2013 due to increased costs of materials and supplies of approximately $5.7 million, outside transportation costs of approximately $4.9 million and utilities costs of approximately $1.8 million. These increases primarily resulted from the incremental revenue generated during the period. As a percentage of revenues, costs decreased 2.2% basis points from operating efficiencies realized at our incinerators and further integration of Safety-Kleen into our waste network.

Industrial and Field Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Cost of revenues	$ 706,093	$ 499,423	$ 513,519	$ 206,670	41.4 %	$ (14,096)	(2.7)%
As a % of Direct Revenue	76.5%	78.1%	77.4%		(1.6)%		0.7 %

Industrial and Field Services cost of revenues for the year ended December 31, 2015 increased 41.4%, or $206.7 million, from the comparable period in 2014 primarily due to increased labor costs of $200.0 million and material costs of $13.3 million, partially offset by decreased fuel expense of $9.3 million. Increases in labor and materials in the year ended December 31, 2015 from the comparable period in 2014 were primarily due to the incremental revenue generated during that period from emergency response service projects. Costs of revenues as a percentage of direct revenue decreased 1.6% for the year ended December 31, 2015 from the comparable period in 2014 primarily due to the increased overall revenue levels experienced during 2015, which outpaced increases in cost structure as well as improved margin on emergency response and unplanned turnaround projects in our Industrial and Field Services business.

Cost of revenues for the year ended December 31, 2014 decreased 2.7%, or $14.1 million, from the comparable period in 2013 primarily due to approximately $14.5 million in decreased labor expense as a result of decreased activity in the markets in which the business operates.

Kleen Performance Products

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Cost of revenues	$ 258,653	$ 264,437	$ 259,905	$ (5,784)	(2.2)%	$ 4,532	1.7%
As a % of Direct Revenue	84.3%	79.7%	77.4%		4.6 %		2.3%

Kleen Performance Products cost of revenues for the year ended December 31, 2015 decreased 2.2%, or $5.8 million, from the comparable period in 2014. The decrease in costs was driven by savings associated with oil additives and other raw materials of $25.0 million, utility costs of $3.3 million and transportation costs of $6.2 million. These cost reductions were offset by adjustments to the value of higher priced used oil inventory on hand during the first half of the year of approximately $30.0 million. As a percentage of revenues, these costs increased 4.6% in the year ended December 31, 2015 from the comparable period in 2014 primarily as a result of the lower pricing realized in 2015 on base and blended oil products combined with the higher inventory cost that was realized during the periods shown.

Cost of revenues for the year ended December 31, 2014 increased 1.7%, or $4.5 million, from the comparable period in 2013 primarily due to increases of $9.0 million in rail transportation costs, $4.0 million in utilities cost, $5.2 million in materials and labor which are all associated with the acquisition of Evergreen. These increases were offset by cost savings related to transportation costs of $8.4 million and the reduced costs of oil additives and other raw materials of $8.2 million. As a percentage of revenues, these costs increased 2.3% as a result of the price declines seen in base and blended oil products primarily in the second half of 2014.

SK Environmental Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Cost of revenues	$ 390,664	$ 524,280	$ 551,129	$ (133,616)	(25.5)%	$ (26,849)	(4.9)%
As a % of Direct Revenue	61.5%	70.1%	71.4%		(8.6)%		(1.3)%

SK Environmental Services cost of revenues for the year ended December 31, 2015 decreased 25.5%, or $133.6 million, from the comparable period in 2014 primarily due to decreases in costs attributable to used oil collections in the amounts of $151.9 million, partially offset by increases across various expense categories commensurate with the increases in parts washer services and other environmental services provided. As a percentage of revenue these costs decreased 8.6% in the year ended December 31, 2015 from the comparable period in 2014. The improved margins were most significantly impacted by the lower used oil collection costs implemented in 2015.

Cost of revenues for the year ended December 31, 2014 decreased 4.9%, or $26.8 million, from the comparable period in 2013 primarily due to decreases in costs attributable to used oil collections in the amounts of $16.2 million and solvent purchases of $10.2 million. As a percentage of revenue, these costs decreased 1.3% in the year ended December 31, 2014 from the comparable period in 2013. The improved margins were most significantly impacted by the lower used oil collection costs in 2014.

Lodging Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Cost of revenues	$ 70,331	$ 108,066	$ 127,259	$ (37,735)	(34.9)%	$ (19,193)	(15.1)%
As a % of Direct Revenue	76.7%	61.8%	59.9%		14.9 %		1.9 %

Lodging Services cost of revenues for the year ended December 31, 2015 decreased 34.9%, or $37.7 million, from the comparable period in 2014. These changes were primarily due to decreases in production material costs associated with manufacturing of $6.9 million, catering costs of $14.2 million and labor costs of $12.0 million during the year ended December 31, 2015 from the comparable period in 2014. These decreases were the result of overall lower demand for lodging segment services as overall activity in the regions in which the business operates declined. As a percentage of direct revenues, these costs increased 14.9% in the year ended December 31, 2015 from the comparable period in 2014 as certain fixed costs incurred in the operations of our camps and lodges could not be reduced proportionate to the pricing and activity declines seen in the business.

Cost of revenues for the year ended December 31, 2014 decreased 15.1%, or $19.2 million, from the comparable period in 2013. These changes were primarily due to decreases in material costs associated with manufacturing of $9.0 million and catering costs of $9.0 million during the year ended December 31, 2014 from the comparable period in 2013. As a percentage of revenues, these costs increased 1.9% as certain fixed costs incurred in the operations of our camps and lodges could not be reduced proportionate to the pricing declines seen in the business.

Oil and Gas Field Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Cost of revenues	$ 160,840	$ 244,642	$ 295,659	$ (83,802)	(34.3)%	$ (51,017)	(17.3)%
As a % of Direct Revenue	88.5%	79.4%	75.7%		9.1 %		3.7 %

Oil and Gas Field Services cost of revenues for the year ended December 31, 2015 decreased 34.3%, or $83.8 million, from the comparable period in 2014 primarily due to decreases in labor related costs of $35.5 million, costs associated with rental equipment of $22.6 million, fuel expense costs of $7.7 million, repairs and maintenance costs of $5.9 million and an

additional $12.1 million in cost reductions seen across various expense categories. As a percentage of direct revenues, these costs increased 9.1% in the year ended December 31, 2015 from the comparable period in 2014. These increases resulted from certain fixed costs incurred which could not be reduced proportionate to the overall lower revenue generated.

Cost of revenues for the year ended December 31, 2014 decreased 17.3%, or $51.0 million, from the comparable period in 2013 primarily due to decreases in labor related costs of approximately $21.3 million, costs associated with rental equipment of $11.8 million, equipment repair costs of approximately $8.6 million and fuel expense costs of $2.2 million in connection with overall lower business activity and revenues. As a percentage of revenues these costs increased 3.7% as fixed costs incurred by the business remained despite the downturn in demand for the segment's services.

Corporate Items

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
Cost of revenues	$ 600	$ 9,124	$ 15,690	$ (8,524)	(93.4)%	$ (6,566)	(41.8)%

Corporate Items cost of revenues decreased $8.5 million for the year ended December 31, 2015 from the comparable period in 2014 primarily due to decreases in insurance related costs recorded within the corporate segment of $6.7 million.

Cost of revenues decreased $6.6 million for the year ended December 31, 2014 from the comparable period in 2013 primarily due to the impact on Safety-Kleen's non-cash acquisition inventory accounting adjustments at December 28, 2012.

Selling, General and Administrative Expenses

Selling, General and Administrative Expenses represent costs incurred in aspects of our business which are not directly attributable to the sale of our services and/or products. We strive to manage such costs commensurate with the overall performance of our segments and corresponding revenue levels. We believe that the ability to properly align these costs with overall business performance is reflective of our strong management of the businesses and further promotes our ability to remain competitive in the marketplace.

Technical Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
SG&A	$ 77,718	$ 85,429	$ 82,823	$ (7,711)	(9.0)%	$ 2,606	3.1 %
As a % of Direct Revenue	6.8%	7.1%	7.2%		(0.3)%		(0.1)%

Technical Services selling, general and administrative expenses for the year ended December 31, 2015 decreased 9.0%, or $7.7 million, from the comparable period in 2014 primarily due to decreases in variable compensation of $2.7 million and changes in estimates for environmental liabilities of $3.6 million.

Selling, general and administrative expenses for the year ended December 31, 2014 increased 3.1%, or $2.6 million, from the comparable period in 2013 primarily due to increases in variable compensation of approximately $5.8 million, partially offset by cost saving initiatives of approximately $2.5 million across various expense categories.

Industrial and Field Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
SG&A	$ 60,006	$ 52,355	$ 53,266	$ 7,651	14.6 %	$ (911)	(1.7)%
As a % of Direct Revenue	6.5%	8.2%	8.0%		(1.7)%		0.2 %

Industrial and Field Services selling, general and administrative expenses for the year ended December 31, 2015 increased 14.6%, or $7.7 million, from the comparable period in 2014 primarily due to increases in marketing costs of $2.5 million and professional fees of $1.4 million. As a percentage of direct revenues selling, general and administrative expense decreased 1.7% in the year ended December 31, 2015 from the comparable period in 2014 primarily due to the increased revenues attributable to this segment which were achieved without significant and incremental SG&A related costs.

Selling, general and administrative expenses for the year ended December 31, 2014 decreased 1.7%, or $0.9 million, from the comparable period in 2013 primarily due to cost saving initiatives across various expense categories of approximately $3.3 million partially offset by increased variable compensation of approximately $1.9 million.

Kleen Performance Products

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
SG&A	$ 15,983	$ 15,725	$ 18,719	$ 258	1.6%	$ (2,994)	(16.0)%
As a % of Direct Revenue	5.2%	4.7%	5.6%		0.5%		(0.9)%

Kleen Performance Products selling, general and administrative expenses remained consistent for the year ended December 31, 2015 as compared to 2014.

Selling, general and administrative expenses for the year ended December 31, 2014 decreased 16.0%, or $3.0 million, from the comparable period in 2013 primarily due to cost saving initiatives of approximately $2.7 million across various expense categories and lower integration related professional fees of approximately $0.6 million.

SK Environmental Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
SG&A	$ 104,127	$ 109,473	$ 108,248	$ (5,346)	(4.9)%	$ 1,225	1.1%
As a % of Direct Revenue	16.4%	14.6%	14.0%		1.8 %		0.6%

SK Environmental selling, general and administrative expenses for the year ended December 31, 2015 decreased 4.9%, or $5.3 million, from the comparable period in 2014 primarily due to decreases in marketing costs of $4.3 million and professional fees of $2.3 million. As a percentage of direct revenues, costs increased primarily due to the fact that the segment's direct revenues decreased as intersegment revenues from used oil sales were significantly reduced.

Selling, general and administrative expenses for the year ended December 31, 2014 increased 1.1%, or $1.2 million, from the comparable period in 2013 primarily due to an increase in variable compensation of approximately $4.7 million and marketing expenses of approximately $2.1 million partially offset by cost saving initiatives of approximately $6.6 million across various expense categories.

Lodging Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
SG&A	$ 4,904	$ 5,228	$ 4,768	$ (324)	(6.2)%	$ 460	9.6%
As a % of Direct Revenue	5.3%	3.0%	2.2%		2.3 %		0.8%

Lodging Services selling, general and administrative expenses remained consistent over the year ended December 31, 2015 from the comparable period in 2014. As a percentage of direct revenues selling, general and administrative expense increased 2.3% in the year ended December 31, 2015 from the comparable period in 2014 as certain fixed costs incurred in the operations of our camps and lodges could not be reduced proportionate to the pricing declines seen in the business.

Selling, general and administrative expenses remained consistent for the year ended December 31, 2014 from the comparable period in 2013.

Oil and Gas Field Services

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
SG&A	$ 21,767	$ 23,514	$ 26,991	$ (1,747)	(7.4)%	$ (3,477)	(12.9)%
As a % of Direct Revenue	12.0%	7.6%	6.9%		4.4 %		0.7 %

Oil and Gas Field Services selling, general and administrative expenses for the year ended December 31, 2015 decreased 7.4%, or $1.7 million, from the comparable period in 2014 primarily due to decreases in salaries and benefits costs of $3.1 million partially offset by increased legal costs of $1.4 million. As a percentage of direct revenues selling, general and administrative expense increased 4.4% in the year ended December 31, 2015 from the comparable period in 2014 primarily because certain fixed costs incurred could not be reduced proportionate to the overall lower business activity.

Selling, general and administrative expenses for the year ended December 31, 2014 decreased 12.9%, or $3.5 million, from the comparable period in 2013 primarily due to decreases in labor related costs of $1.2 million and an additional $2.3 million decrease across various expense categories as a result of our cost saving initiatives.

Corporate Items

	For the years ended December 31,			2015 over 2014		2014 over 2013	
	2015	2014	2013	$ Change	% Change	$ Change	% Change
SG&A	$ 129,659	$ 146,197	$ 175,662	$ (16,538)	(11.3)%	$ (29,465)	(16.8)%

Corporate Items selling, general and administrative expenses for the year ended December 31, 2015 decreased 11.3%, or $16.5 million, from the comparable period in 2014 primarily due to decreases in variable compensation and related payroll taxes of $11.7 million and labor and benefit related costs of $3.0 million.

Selling, general and administrative expenses for the year ended December 31, 2014 decreased 16.8%, or $29.5 million, from the comparable period in 2013 primarily due to cost saving initiatives resulting in lower salaries and benefits expense of approximately $4.0 million, lower professional fees of approximately $14.7 million related primarily to acquisition and system integration related costs that did not reoccur in 2014 and a decrease of approximately $5.4 million of insurance related costs resulting from improved claims experience and integration synergies.

Adjusted EBITDA

Management considers Adjusted EBITDA to be a measurement of performance which provides useful information to both management and investors. Adjusted EBITDA should not be considered an alternative to net income or other measurements under generally accepted accounting principles ("GAAP"). Adjusted EBITDA is not calculated identically by all companies and, therefore our measurements of Adjusted EBITDA may not be comparable to similarly titled measures reported by other companies.

We use Adjusted EBITDA to enhance our understanding of our operating performance, which represents our views concerning our performance in the ordinary, ongoing and customary course of our operations. We historically have found it helpful, and believe that investors have found it helpful, to consider an operating measure that excludes certain expenses relating to transactions not reflective of our core operations.

The information about our operating performance provided by this financial measure is used by our management for a variety of purposes. We regularly communicate Adjusted EBITDA results to our lenders and to our board of directors and discuss with the board our interpretation of such results. We also compare our Adjusted EBITDA performance against internal targets as a key factor in determining cash bonus compensation for executives and other employees, largely because we believe that this measure is indicative of how the fundamental business is performing and is being managed.

We also provide information relating to our Adjusted EBITDA so that analysts, investors and other interested persons have the same data that we use to assess our core operating performance. We believe that Adjusted EBITDA should be viewed only as a supplement to the GAAP financial information. We also believe, however, that providing this information in addition to, and together with, GAAP financial information permits the foregoing persons to obtain a better understanding of our core operating performance and to evaluate the efficacy of the methodology and information used by management to evaluate and measure such performance on a standalone and a comparative basis.

The following is a reconciliation of net income to Adjusted EBITDA for the following periods (in thousands):

	Year Ended December 31,		
	2015	2014	2013
Net income (loss)	$ 44,102	$ (28,328)	$ 95,566
Accretion of environmental liabilities	10,402	10,612	11,541
Depreciation and amortization	274,194	276,083	264,449
Goodwill impairment charge	31,992	123,414	—
Other expense (income)	1,380	(4,380)	(1,705)
Interest expense, net	76,553	77,668	78,376
Pre-tax, non-cash acquisition accounting inventory adjustments	—	—	13,559
Provision for income taxes	65,544	66,850	48,319
Adjusted EBITDA	$ 504,167	$ 521,919	$ 510,105

Depreciation and Amortization

	Year Ended December 31,			2015 over 2014		2014 over 2013	
(in thousands)	2015	2014	2013	$ Change	% Change	$ Change	% Change
Depreciation of fixed assets and landfill amortization	$ 233,998	$ 239,410	$ 229,392	$ (5,412)	(2.3)%	$ 10,018	4.4%
Permits and other intangibles amortization	40,196	36,673	35,057	3,523	9.6 %	1,616	4.6%
Total depreciation and amortization	$ 274,194	$ 276,083	$ 264,449	$ (1,889)	(0.7)%	$ 11,634	4.4%

Depreciation of fixed assets and landfill amortization decreased $5.4 million for the year ended December 31, 2015 compared to the comparable period in 2014 primarily due to lower landfill volumes generated in the year ended December 31, 2015 which resulted in $2.9 million of lower amortization in those periods. Permits and other intangibles amortization increased $3.5 million for the year ended December 31, 2015 compared to the comparable period in 2014 primarily due to an increased intangible base in 2015. The increased intangible base was attributable to intangible assets recognized in the acquisition of TFI which occurred in April of 2015.

Depreciation of fixed assets and landfill amortization increased $10.0 million for the year ended December 31, 2014 compared to the comparable period in 2013 primarily due to higher landfill volumes generated in the year ended December 31, 2014 which resulted in greater amortization in 2014. Permits and other intangibles amortization also increased $1.6 million for the year ended December 31, 2014 compared to the comparable period in 2014 primarily due to an increased intangible base in 2014. The increased intangible base was primarily attributable to intangible assets recognized in the two privately owned companies we acquired in 2014.

Goodwill impairment charge

	Year Ended December 31,			2015 over 2014		2014 over 2013	
(in thousands)	2015	2014	2013	$ Change	% Change	$ Change	% Change
Goodwill impairment charge	$ 31,992	$ 123,414	$ —	$ (91,422)	100.0%	$ 123,414	—%

During the year ended December 31, 2015, we recorded a $32.0 million goodwill impairment charge in our Oil and Gas Field Services reporting unit. During the year ended December 31, 2014, we recorded a $123.4 million goodwill impairment charge on our Kleen Performance Products reporting unit. For additional information regarding our 2015 and 2014 goodwill impairment charges, see the discussion under the goodwill heading within our "Critical Accounting Policies and Estimates" below.

Other (Expense) Income

	Year Ended December 31,			2015 over 2014		2014 over 2013	
(in thousands)	2015	2014	2013	$ Change	% Change	$ Change	% Change
Other (expense) income	$ (1,380)	$ 4,380	$ 1,705	$ (5,760)	(131.5)%	$ 2,675	(156.9)%

Other (expense) income decreased 131.5%, or $5.8 million, for the year ended December 31, 2015 as compared to 2014 primarily due to losses recognized on the sale of fixed assets which occurred in 2015 and 2014 gains on the sale of

investments which did not occur in 2015. For the year ended December 31, 2014, other (expense) income increased $2.7 million from the comparable period in 2013 primarily due to gains recognized from the sale of investments which occurred in 2014.

Provision for Income Taxes

	Year Ended December 31,			2015 over 2014		2014 over 2013	
(in thousands)	2015	2014	2013	$ Change	% Change	$ Change	% Change
Provision for income taxes	$ 65,544	$ 66,850	$ 48,319	$ (1,306)	(2.0)%	$ 18,531	38.4%

Income tax expense remained consistent over the year ended December 31, 2015 from the comparable period in 2014. Income tax expense increased $18.5 million for the year ended December 31, 2014 from the comparable period in 2013. The increase was a result of the increased earnings in the United States and the continued losses in Canada during 2014.

Effective tax rates for the years ended December 31, 2015, 2014 and 2013 were 59.8%, 173.5% and 33.6%, respectively. In 2015 and 2014, we recorded an income tax benefit of $2.0 million and $2.7 million, respectively, as a result of the goodwill impairment charge. Absent the impact of the impairment charge on pre-tax income from operations, the Company's effective tax rate for 2015 and 2014 was 47.7% and 40.6%, respectively. The increase in the effective rates absent the impact of impairment charges for the year ended December 31, 2015 as compared to 2014 was primarily due to an increase in the proportionate share of our pre-tax income being generated by the United States operations combined with losses being generated in Canadian operations and benefiting us at a lower statutory tax rate and for an increase in the valuation allowance and true ups of deferred balances for rate increases. The increase in the effective rate absent the impact of the impairment charge for the year ended December 31, 2014 as compared to the 2013 effective rate is primarily due to an increase in the proportionate share of our pre-tax income being generated by the United States operations and the result of the release of unrecognized tax benefits in 2013.

Liquidity and Capital Resources

	For the years ended December 31,		
(in thousands)	2015	2014	2013
Net cash from operating activities	$ 396,383	$ 297,366	$ 415,839
Net cash used in investing activities	(350,642)	(258,294)	(345,512)
Net cash (used in) from financing activities	(90,179)	(93,945)	13,126

Net cash from operating activities

Net cash from operating activities for the year ended December 31, 2015 was $396.4 million, an increase of 33.3%, or $99.0 million, compared with net cash from operating activities for the year ended December 31, 2014. The change was primarily the result of improved management of working capital in 2015, more specifically from the timing of accounts receivable collections and decreased levels of inventories and supplies as compared to the prior year. For the year ended December 31, 2014, net cash from operating activities was $297.4 million, a decrease of 28.5%, or $118.5 million, compared with cash from operating activities for the year ended December 31, 2013. The change was primarily the result of a net increase in working capital driven by the timing associated with payment of liabilities in 2014 as compared to the prior year.

Net cash used in investing activities

Net cash used in investing activities for the year ended December 31, 2015 was $350.6 million, an increase of 35.8%, or $92.3 million, compared with cash used in investing activities for the year ended December 31, 2014. The change was primarily driven by an increase in cash paid for acquisitions in 2015 and decrease in proceeds from investment sales that occurred in 2014 and did not reoccur in 2015. For the year ended December 31, 2014, net cash used in investing activities was $258.3 million, a decrease of 25.2%, or $87.2 million, compared with cash used in investing activities for the year ended December 31, 2013. The change was primarily the result of decreases in capital expenditures and cash paid for acquisitions as well as proceeds received from the sale of investments which did not occur in 2013.

Net cash (used in) from financing activities

Net cash used in financing activities for the year ended December 31, 2015 was $90.2 million, a decrease of 4.0%, or $3.8 million, compared with cash used in financing activities for the year ended December 31, 2014. The change in net cash used in financing activities during the year ended December 31, 2015 was primarily due to a decrease in repurchases of common stock and a reduction in payments on capital leases in 2015 as compared to 2014, offset by changes in and from the timing of uncashed checks. For the year ended December 31, 2014, net cash (used in) from financing activities was $93.9 million, a decrease of $107.1 million, compared to net cash (used in) from financing activities for the year ended December 31, 2013. The change in net cash (used in) from financing activities during the year ended December 31, 2014 was primarily due to repurchases of common stock and a $5.0 million payment of outstanding senior notes, neither of which occurred in 2013.

Working Capital

At December 31, 2015, cash and cash equivalents totaled $184.7 million, compared to $246.9 million at December 31, 2014. At December 31, 2015, cash and cash equivalents held by foreign subsidiaries totaled $90.2 million and were readily convertible into other foreign currencies including U.S. dollars. At December 31, 2015, the cash and cash equivalents balance for our U.S. operations was $94.5 million, and our U.S. operations had net operating cash flows of $324.1 million for the year ended December 31, 2015. Additionally, we have a $400.0 million revolving credit facility of which approximately $178.5 million was available to borrow at December 31, 2015. Based on the above and our current plans, we believe that our U.S. operations have adequate financial resources to satisfy their liquidity needs without being required to repatriate earnings from foreign subsidiaries. Accordingly, although repatriation to the U.S. of foreign earnings would generally be subject to U.S. income taxation, net of any available foreign tax credits, we have not recorded any deferred tax liability related to such repatriation since we intend to permanently reinvest foreign earnings outside the U.S.

We assess our liquidity in terms of our ability to generate cash to fund our operating, investing, and financing activities. Our primary ongoing cash requirements will be to fund operations, capital expenditures, interest payments and investments in line with our business strategy. We believe our future operating cash flows will be sufficient to meet our future operating and internal investing cash needs as well as any cash needs relating to our stock repurchase program. Furthermore, the existing cash balances and the availability of additional borrowings under our revolving credit facility provide additional potential sources of liquidity should they be required.

Financing Arrangements

The financing arrangements and principal terms of our $800.0 million principal amount of 5.25% senior unsecured notes due 2020 and $595.0 million principal amount of 5.125% senior unsecured notes due 2021 which were outstanding at December 31, 2015, and our $400.0 million revolving credit facility, are discussed further in Note 10, “Financing Arrangements,” to our consolidated financial statements included in Item 8 of this report.

As of December 31, 2015, we were in compliance with the covenants of all of our debt agreements, and we believe we will continue to meet such covenants.

Environmental Liabilities

	As of December 31,		2015 over 2014	
(in thousands)	2015	2014	$ Change	% Change
Closure and post-closure liabilities	$ 56,249	$ 50,701	$ 5,548	10.9 %
Remedial liabilities	131,992	155,121	(23,129)	(14.9)%
Total environmental liabilities	$ 188,241	$ 205,822	$ (17,581)	(8.5)%

Total environmental liabilities as of December 31, 2015 were $188.2 million, a decrease of 8.5%, or $17.6 million, compared to the liabilities as of the comparable date in 2014 primarily due to expenditures and changes in estimates recorded to the statement of income partially offset by accretion.

We anticipate our environmental liabilities, substantially all of which we assumed in connection with our acquisitions, will be payable over many years and that cash flow from operations will generally be sufficient to fund the payment of such liabilities when required. However, events not anticipated (such as future changes in environmental laws and regulations) could require that such payments be made earlier or in greater amounts than currently anticipated, which could adversely affect our results of operations, cash flow and financial condition.

During each of 2015, 2014 and 2013, we benefited from reductions in our environmental liabilities due to changes in estimates recorded to the statement of income. The benefits over these years were primarily due to the successful introduction

of new technology for remedial activities, favorable results from environmental studies of the on-going remediation, including favorable regulatory approvals, and lower project costs realized by utilizing internal labor and equipment. The principal changes in estimates were from the following items:

In 2015, the net reduction in our environmental liabilities from changes in estimates recorded to the statement of income (loss) was $11.3 million and primarily related to reductions in the estimates for remedial activities at four locations. Events which occurred during 2015 and resulted in the changes in estimates were attributable to favorable outcomes from negotiations amongst potentially responsible parties (or "PRPs") which we participate in of $3.8 million, the results of work performed by external third party consultants whom were engaged to aid us in estimating future remedial activity costs at certain sites of $4.7 million and the result of receiving Provincial approval for a planned expansion of one of our landfills in Canada which as a result will remediate our previously recognized obligations of $2.5 million.

In 2014, the net reduction in our environmental liabilities from changes in estimates recorded to the statement of income was $3.4 million and primarily related to reductions in the estimates associated with future monitoring costs of certain sites and favorable settlement with PRPs which we were part of.

In 2013, the net reduction in our environmental liabilities from changes in estimates recorded to the statement of income was $3.7 million and primarily related to two sites. One site received site closure approval, which resulted in reevaluating and removing certain compensation costs, and at the other site we received a favorable notification from the PRPs group which indicated that the Interim Remedial Measure work had been completed and was fully funded by a trust held by the regulatory agency and from funds collected from settling PRPs.

Contractual Obligations

The following table has been included to assist the reader in analyzing our debt and similar obligations as of December 31, 2015 and our ability to meet such obligations (in thousands):

		Payments Due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Closure, post-closure and remedial liabilities	$ 457,791	$ 21,685	$ 47,973	$ 31,652	$ 356,481
Long-term obligations, at par	1,395,000	—	—	800,000	595,000
Interest on long-term obligations	357,676	72,494	144,988	127,488	12,706
Operating leases	142,978	37,064	51,124	30,403	24,387
Total contractual obligations	$ 2,353,445	$ 131,243	$ 244,085	$ 989,543	$ 988,574

The undiscounted value of closure, post closure and remedial liabilities of $457.8 million is equivalent to the present value of $188.2 million based on discounting of $182.3 million and the undiscounted remainder of $87.3 million to be accrued for closure and post-closure liabilities over the remaining site lives.

The following table has been included to assist the reader in understanding other contractual obligations we had as of December 31, 2015 and our ability to meet these obligations (in thousands):

		Payments Due by Period			
Other Commercial Commitments	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Standby letters of credit	$ 144,573	$ 144,573	$ —	$ —	$ —

We obtained the standby letters of credit described in the above table primarily as security for financial assurances which we have been required to provide to regulatory bodies for our hazardous waste facilities and which would be called only in the event that we fail to satisfy closure, post-closure and other obligations under the permits issued by those regulatory bodies for such licensed facilities. See Note 10, "Financing Arrangements," to our consolidated financial statements included in Item 8 of this report for further discussion of our standby letters of credit and other financing arrangements.

Off-Balance Sheet Arrangements

Except for our obligations under operating leases and letters of credit described above under "Contractual Obligations" and performance obligations incurred in the ordinary course of business, we are not party to any off-balance sheet arrangements involving guarantee, contingency or similar obligations to entities whose financial statements are not consolidated with our results, and that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that would be material to investors in our securities.

Capital Expenditures

We anticipate that 2016 capital spending will be below $200 million. This excludes the construction of the new incinerator at our El Dorado, Arkansas facility, which will likely add $45-$50 million in 2016. However, changes in environmental regulations could require us to make significant capital expenditures for our facilities and adversely affect our results of operations and cash flow.

Stockholder Matters

On March 13, 2015, our board of directors authorized the repurchase of up to $300 million of our common stock. The repurchase program authorizes us to purchase our common stock on the open market from time to time. As of December 31, 2015, we repurchased and retired a total of approximately 3.4 million shares of our common stock for approximately $177.7 million under this program. As of December 31, 2015, an additional $122.3 million remained available for repurchase of shares under the current authorized program. We have funded and intend to fund future repurchases through available cash resources. The share repurchases have been and will be made in a manner that complies with applicable U.S. securities laws. The number of shares purchased and the timing of the purchases will depend on a number of factors, including share price, cash required for future business plans, trading volume and other conditions. We have no obligation to repurchase stock under this program and may suspend or terminate the repurchase program at any time.

Critical Accounting Policies and Estimates

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of our assets, liabilities, revenues and expenses, and related disclosures of contingent liabilities. The following are the areas that we believe require the greatest amount of judgments or estimates in the preparation of the financial statements: revenue allowance, allowance for doubtful accounts, accounting for landfills, non-landfill closure and post-closure liabilities, remedial liabilities, goodwill, permits and other intangible assets, insurance accruals, legal matters, and provision for income taxes. Our management reviews critical accounting estimates with the Audit Committee of our Board of Directors on an ongoing basis and as needed prior to the release of our annual financial statements. See also Note 2, "Significant Accounting Policies," to our consolidated financial statements included in Item 8 of this report, which discusses the significant assumptions used in applying our accounting policies.

Revenue Allowance. Due to the nature of our business and the invoices that result from the services we provide, customers may withhold payments and attempt to renegotiate amounts invoiced. In addition, for some of the services we provide, our invoices are based on quotes that can either generate credits or debits when the actual revenue amount is known. Accordingly, based on our industry knowledge and historical trends, we record a revenue allowance. Increases in overall sales volumes and the expansion of our customer base in recent years have also increased the volume of additions and deductions to the allowance during the year, as well as increased the amount of the allowance at the end of the year.

Our revenue allowance is intended to cover the net amount of revenue adjustments that may need to be credited to customers' accounts in future periods. We determine the appropriate total revenue allowance by evaluating the following factors on a customer-by-customer basis as well as on a consolidated level: historical collection trends, age of outstanding receivables, existing economic conditions and other information as deemed applicable. Revenue allowance estimates can differ materially from the actual adjustments, but historically our revenue allowance has been sufficient to cover the net amount of the reserve adjustments recorded in subsequent reporting periods.

Allowance for Doubtful Accounts. We establish an allowance for doubtful accounts to cover accounts receivable that may not be collectible. In establishing the allowance for doubtful accounts, we analyze the collectability of accounts that are large or past due. A considerable amount of judgment is required to make this assessment, based on detailed analysis of the aging of our receivables, the creditworthiness of our customers, our historical bad debts and other adjustments and current economic trends, for instance, seen in the oil and gas markets in Western Canada. Accounts receivable written off in subsequent periods can differ materially from the allowance for doubtful accounts provided, but historically our provision has been adequate.

Landfill Accounting. We amortize landfill improvements and certain landfill-related permits over their estimated useful lives. The units-of-consumption method is used to amortize land, landfill cell construction, asset retirement costs and remaining landfill cells and sites. We also utilize the units-of-consumption method to record closure and post-closure obligations for landfill cells and sites. Under the units-of-consumption method, we include future estimated construction and asset retirement costs, as well as costs incurred to date, in the amortization base of the landfill assets. Additionally, where appropriate, as discussed below, we include probable expansion airspace that has yet to be permitted in the calculation of the total remaining useful life of the landfill. If we determine that expansion capacity should no longer be considered in calculating the recoverability of a landfill asset, we may be required to recognize an asset impairment or incur significantly higher

amortization expense. If at any time we make the decision to abandon the expansion effort, the capitalized costs related to the expansion effort are expensed immediately.

Landfill Assets. Landfill assets include the costs of landfill site acquisition, permits and cell construction incurred to date. These amounts are amortized under the units-of-consumption method such that the asset is completely amortized when the landfill ceases accepting waste.

Landfill Capacity. Landfill capacity, which is the basis for the amortization of landfill assets and for the accrual of final closure and post-closure obligations, represents total permitted airspace plus unpermitted airspace that management believes is probable of ultimately being permitted based on established criteria. Our management applies the following criteria for evaluating the probability of obtaining a permit for future expansion airspace at existing sites, which provides management a basis to evaluate the likelihood of success of unpermitted expansions:

- Personnel are actively working to obtain the permit or permit modifications (land use, state and federal) necessary for expansion of an existing landfill, and progress is being made on the project.
- Management expects to submit the application within the next year and to receive all necessary approvals to accept waste within the next five years.
- At the time the expansion is included in management's estimate of the landfill's useful economic life, it is probable that the required approvals will be received within the normal application and processing time periods for approvals in the jurisdiction in which the landfill is located.
- Our Company or other owner of the landfill has a legal right to use or obtain the right to use the land associated with the expansion plan.
- There are no significant known political, technical, legal or business restrictions or other issues that could impair the success of such expansion.
- A financial feasibility analysis has been completed and the results demonstrate that the expansion will have a positive financial and operational impact such that management is committed to pursuing the expansion.
- Additional airspace and related additional costs, including permitting, final closure and post-closure costs, have been estimated based on the conceptual design of the proposed expansion.

As of December 31, 2015, there was one unpermitted expansion at one location included in management's landfill calculation, which represented 3.0% of our remaining airspace at that date. If actual expansion airspace is significantly different from management's estimate of expansion airspace, the amortization rates used for the units-of-consumption method would change, therefore impacting our profitability. If we determine that there is less actual expansion airspace at a landfill, this would increase amortization expense recorded and decrease profitability, while if we determine a landfill has more actual expansion airspace, amortization expense would decrease and profitability would increase.

Landfill Final Closure and Post-Closure Liabilities. The balance of landfill final closure and post-closure liabilities at December 31, 2015 and 2014 was $32.0 million and $29.9 million, respectively. We have material financial commitments for the costs associated with requirements of the EPA and the comparable regulatory agency in Canada for landfill final closure and post-closure activities. In the United States, the landfill final closure and post-closure requirements are established under the standards of the EPA, and are implemented and applied on a state-by-state basis. We develop estimates for the cost of these activities based on our evaluation of site-specific facts and circumstances, such as the existence of structures and other landfill improvements that would need to be dismantled, the amount of groundwater monitoring and leachate management expected to be performed, and the length of the post-closure period as determined by the applicable regulatory agency. Included in our cost estimates are our interpretation of current regulatory requirements and proposed regulatory changes. Such estimates may change in the future due to various circumstances including, but not limited to, permit modifications, changes in legislation or regulations, technological changes and results of environmental studies. We perform zero-based reviews of these estimated liabilities at least every five years or sooner if the occurrence of a significant event is likely to change the timing or amount of the currently estimated expenditures. We consider a significant event to be a new regulation or an amendment to an existing regulation, a new permit or modification to an existing permit, or a change in the market price of a significant cost item. Our cost estimates are calculated using internal sources as well as input from third party experts. These costs are measured at estimated fair value using present value techniques, and therefore changes in the estimated timing of closure and post-closure activities would affect the liability, the value of the related asset, and our results of operations.

Final closure costs are the costs incurred after the site ceases to accept waste, but before the landfill is certified as closed by the applicable state or provincial regulatory agency. These costs generally include the costs required to cap the final cell of the landfill (if not included in cell closure), to dismantle certain structures for landfills and other landfill improvements and regulation-mandated groundwater monitoring, and for leachate management. Post-closure costs involve the maintenance and

monitoring of a landfill site that has been certified closed by the applicable regulatory agency. These costs generally include groundwater monitoring and leachate management. Regulatory post-closure periods are generally 30 years after landfill closure. Final closure and post-closure obligations are accrued on a units-of-consumption basis, such that the present value of the final closure and post-closure obligations are fully accrued at the date the landfill discontinues accepting waste.

Non-Landfill Closure and Post-Closure Liabilities. The balance of our non-landfill closure and post-closure liabilities at December 31, 2015 and 2014 was $24.2 million and $20.8 million, respectively. We base estimates for non-landfill closure and post-closure liabilities on our interpretations of existing permit and regulatory requirements for closure and post-closure maintenance and monitoring. Our cost estimates are calculated using internal sources as well as input from third party experts. We use probability scenarios to estimate when future operations will cease and inflate the current cost of closing the non-landfill facility on a probability weighted basis using the appropriate inflation rate and then discounting the future value to arrive at an estimated present value of closure and post-closure costs. The estimates for non-landfill closure and post-closure liabilities are inherently uncertain due to the possibility that permit and regulatory requirements will change in the future, impacting the estimation of total costs and the timing of the expenditures. We review non-landfill closure and post-closure liabilities for changes to key assumptions that would impact the amount of the recorded liabilities. Changes that would prompt us to revise a liability estimate include changes in legal requirements that impact our expected closure plan or scope of work, in the market price of a significant cost item, in the probability scenarios as to when future operations at a location might cease, or in the expected timing of the cost expenditures. Changes in estimates for non-landfill closure and post-closure events immediately impact the required liability and the value of the corresponding asset. If a change is made to a fully-consumed asset, the adjustment is charged immediately to expense. When a change in estimate relates to an asset that has not been fully consumed, the adjustment to the asset is recognized in income prospectively as a component of amortization. Historically, material changes to non-landfill closure and post-closure estimates have been infrequent.

Remedial Liabilities. The balance of our remedial liabilities at December 31, 2015 and 2014 was $132.0 million and $155.1 million, respectively. See Note 9, "Remedial Liabilities," to our consolidated financial statements included in Item 8 of this report for the changes to the remedial liabilities during the years ended December 31, 2015 and 2014. Remedial liabilities are obligations to investigate, alleviate and/or eliminate the effects of a release (or threat of a release) of hazardous substances into the environment and may also include corrective action under RCRA. Our remediation obligations can be further characterized as Long-term Maintenance, One-Time Projects, Legal and Superfund. Legal liabilities are typically comprised of litigation matters that involve potential liability for certain aspects of environmental cleanup and can include third party claims for property damage or bodily injury allegedly arising from or caused by exposure to hazardous substances originating from our activities or operations or, in certain cases, from the actions or inactions of other persons or companies. Superfund liabilities are typically claims alleging that we are a potentially responsible party ("PRP") and/or are potentially liable for environmental response, removal, remediation and cleanup costs at/or from either a facility we own or a site owned by a third party. As described in Note 16, "Commitments and Contingencies," to our consolidated financial statements included in Item 8 of this report, Superfund liabilities also include certain liabilities payable to governmental entities for which we are potentially liable to reimburse the sellers in connection with our 2002 acquisition of substantially all of the assets of the Chemical Services Division (the "CSD assets") of Safety-Kleen Corp. Long-term Maintenance liabilities include the costs of groundwater monitoring, treatment system operations, permit fees and facility maintenance for inactive operations. One-Time Projects liabilities include the costs necessary to comply with regulatory requirements for the removal or treatment of contaminated materials.

Amounts recorded related to the costs required to remediate a location are determined by internal engineers and operational personnel and incorporate input from external third parties. The estimates consider such factors as the nature and extent of environmental contamination (if any); the terms of applicable permits and agreements with regulatory authorities as to cleanup procedures and whether modifications to such permits and agreements will likely need to be negotiated; the cost of performing anticipated cleanup activities based upon current technology; and in the case of Superfund and other sites where other parties will also be responsible for a portion of the cleanup costs, the likely allocation of such costs and the ability of such other parties to pay their share. Each quarter, our management discusses if any events have occurred or milestones have been met that would warrant the creation of a new remedial liability or the revision of an existing remedial liability. Such events or milestones include identification and verification as a PRP, receipt of a unilateral administrative order under Superfund or requirement for RCRA interim corrective measures, completion of the feasibility study under Superfund or the corrective measures study under RCRA, new or modifications to existing permits, changes in property use, or a change in the market price of a significant cost item. Remedial liabilities are inherently difficult to estimate and there is a risk that the actual quantities of contaminants could differ from the results of the site investigation, which could materially impact the amount of our liability. It is also possible that chosen methods of remedial solutions will not be successful and funds will be required for alternative solutions.

Remedial liabilities are discounted only when the timing of the payments is estimable and the amounts are determinable, with the exception of remedial liabilities assumed as part of an acquisition that are measured at fair value.

We establish reserves for estimated environmental liabilities based on acceptable technologies when we determine the liability is appropriate. Introductions of new technologies are subject to successful demonstration of the effectiveness of the alternative technology and regulatory approval. We routinely review and evaluate the sites for which we have established estimated environmental liabilities reserves to determine if there should be changes in the established reserves. The changes in estimates are reflected as adjustments in the ordinary course of business in the period when we determine that an adjustment is appropriate as new information becomes available. Upon demonstration of the effectiveness of the alternative technology and applicable regulatory approval, we update our estimated cost of remediating the affected sites.

Goodwill and Other Long-Lived Assets. Goodwill is not amortized but is reviewed for impairment annually as of December 31 or when events or changes in the business environment indicate the carrying value of the reporting unit may exceed its fair value. This review is performed by comparing the fair value of each reporting unit to its carrying value, including goodwill. If the fair value is less than the carrying amount, a Step II analysis of the fair value of all the elements of the reporting unit is performed to determine if and to what degree goodwill is impaired. The loss, if any, is measured as the excess of the carrying value of the goodwill over the value of the goodwill implied by the results of the Step II analysis.

We determine our reporting units by identifying the components of each operating segment, and then in some circumstances aggregate components having similar economic characteristics based on quantitative and/or qualitative factors. We have determined that we have seven reporting units. Our Technical Services, Kleen Performance Products, SK Environmental Services, Lodging Services and Oil and Gas Field Services segments each constitute a reporting unit. Our Industrial and Field Services segment includes two separate reporting units: Industrial Services and Field Services. As a result of impairment charges recognized in the second quarter of 2015 and discussed more fully below, no goodwill is recorded by the Oil and Gas Field Services segment as of December 31, 2015.

We conducted our annual impairment test of goodwill for all of our reporting units to which goodwill is allocated as of December 31, 2015 and determined that no adjustment to the carrying value of goodwill for any reporting unit was then necessary. In all cases except for our Kleen Performance Products reporting unit, the estimated fair values of each reporting unit significantly exceeded their carrying values. The annual impairment test fair value for all of our reporting units is determined using an income approach (a discounted cash flow analysis) which incorporates several underlying estimates and assumptions with varying degrees of uncertainty. The discounted cash flow analyses include estimated cash flows for a discrete five year future period and for a terminal period thereafter. In all instances, we corroborate our estimated fair values by also considering other factors such as the fair value of comparable companies to businesses contained in our reporting units. As part of the annual test we also perform a reconciliation of the total estimated fair values of all reporting units to our market capitalization.

As disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014, goodwill attributable to the Oil and Gas Field Services reporting unit was at risk of impairment because of lower operating results caused by the depressed economic conditions and lower levels of activity in the oil and gas industry primarily in Western Canada. In consideration of the increased risk of impairment associated with this segment, management regularly evaluated whether any changes in events or circumstances arose which would indicate that the fair value of this reporting unit was less than its carrying value.

During the second quarter of 2015, certain events and changes in circumstances arose which led management to conclude that the fair values of the Oil and Gas Field Services reporting unit more likely than not had reduced to an amount less than its carrying value and therefore an interim impairment test was conducted relative to goodwill recorded by the Oil and Gas Field Services reporting unit. The primary events and changes in circumstances which led to this conclusion were:

- The second quarter is the period of time where greater levels of communication with customers and the receipt of bids and proposals for project work take place and provide management with more clarity into levels of activity and other economic and business indicators for the latter half of the fiscal year and on into the first quarter of the following year. During the quarter ended June 30, 2015, it became apparent that oil and gas exploration and production activity would continue to be lower than historical periods and lower than previously anticipated by our Company. This was evidenced by reduced volume in bid and proposal requests from customers and communications indicating the reduction in customer budgets in these areas as well as lower than anticipated pricing for our services.

- Market and industry reports which management looks to in projecting business conditions and establishing forecast information evidenced more pessimistic views in the near term. The continued depressed price of oil without any upward momentum since December 2014, as well as declining and expected continued decline in rig count for the remainder of 2015, resulted in lower estimates of industry activity in the second half of 2015 and early 2016.

- In recognition of lower than anticipated business results and less optimistic market indicators, management significantly lowered its 2015 forecasts relative to the Oil and Gas Field Services reporting unit.

Significant judgments and unobservable inputs categorized as Level III in the fair value hierarchy are inherent in the impairment tests performed and include assumptions about the amount and timing of expected future cash flows, growth rates, profit margins and the determination of appropriate discount rates. In performing the Step I test as of June 30, 2015 certain of these significant assumptions changed from those utilized in performing our annual goodwill impairment test as of December 31, 2014. Based upon information known as of June 30, 2015, we reduced the estimates and assumptions around FY2015 annual revenue growth from 1% of growth to a contraction in 2015 revenues of 24%. This decrease resulted largely from projects which were expected to occur in the second half of 2015 but had then been canceled or reduced as well as updated outlooks on pricing of our services. EBITDA margins relative to 2015 were also reduced from estimates of 13% utilized in the most recent annual test to 6%. Prior to the impairment we had assumed greater EBITDA margin expansion driven by more positive revenue growth which increased estimated future cash flows. The reduction in margin assumptions utilized in the June 30, 2015 Step I test was based upon the lower levels of revenue then forecasted for 2015, lower pricing of our services and less than anticipated cost savings from cost cutting measures which had been planned but had not fully materialized as of June 30, 2015. These lower revenue and margin estimates associated with 2015 resulted in lower expectations and cash flows in 2015 and also led to decreases in expected revenues and cash flows in future periods, thus lengthening our assumptions around the recovery from the current business downturn as compared to assumptions utilized in prior tests. The changes in these estimates and business assumptions had significant negative impact on our estimates of future anticipated cash flows used in our impairment test and therefore on our estimates of the fair value of the Oil and Gas Field Services reporting unit. Discount rate assumptions utilized in the June 30, 2015 test were consistent with those used in the December 31, 2014 annual test. The results of the Step I test conducted as of June 30, 2015 indicated that the estimated fair value of the reporting unit was less than its carrying value and therefore a Step II test was performed to determine if and in what amount goodwill recorded by the Oil and Gas Field Services segment was impaired. The results of the Step II test indicated that as of June 30, 2015, the total amount of goodwill recorded by the reporting unit was impaired and as such a $32.0 million impairment charge was recorded and is reflected in the 2015 operating results.

During the fiscal quarter ended September 30, 2014, we recorded a $123.4 million impairment charge related to goodwill recorded by the Kleen Performance Products reporting unit. Decreasing market prices associated with the reporting unit's oil products which began to occur in the third quarter of 2014 was the predominant factor which led to the charge being recognized in the third quarter of 2014. The charge was recognized after developing an estimate of the reporting unit's fair value as of September 30, 2014 and conducting Step I and Step II goodwill impairment tests. Significant judgments and estimates were utilized in estimating the fair value of the Kleen Performance Products reporting unit as of September 30, 2014 including the timing of expected future cash flows, pricing assumptions and related revenue growth rates, product mix, overall profit margins and the determination of appropriate discount rates. In performing the Step I test as of September 30, 2014, certain of these significant assumptions changed from those utilized in performing our annual goodwill impairment test as of December 31, 2013. Based upon information known as of September 30, 2014, assumptions surrounding the pricing of our products were significantly decreased resulting in FY2014 and 2015 growth rates being reduced from 13% and 4% respectively to -5% and 2%. These changes in revenue assumptions significantly impacted the estimated fair value of the reporting unit.

During the year ended December 31, 2015, we continued to evaluate the Kleen Performance Products reporting unit's performance and monitor for events or changes in circumstances which might indicate that the estimated fair value of the Kleen Performance Products reporting unit was below its carrying value. Despite continued decreases in overall pricing and in turn, lower revenues generated by the business, cost reductions and in particular successful management of costs associated with used oil raw materials and other expenses led to conclusions that no further impairments existed in 2015.

Accordingly, in conducting our December 31, 2015 goodwill impairment test, we determined that the estimated fair value of the Kleen Performance Products reporting unit exceeded its carrying value by 19%. Significant assumptions included in the discounted cash flow model utilized to estimate the reporting unit's fair value were a compounded annual revenue growth assumption of approximately 5% over the five year discrete period and 3% thereafter, EBITDA margins consistent with the historical performance of the business and a weighted average cost of capital assumption equal to 12% which was utilized to discount the estimated future cash flows of the business in order to estimate its current fair value.

See further information related to the goodwill impairment charges recorded in Note 6, "Goodwill and Other Intangible Assets," to our consolidated financial statements included in Item 8 of this report.

Indefinite-lived intangible assets are not amortized but are reviewed for impairment annually as of December 31, or when events or changes in the business environment indicate that the carrying value may be impaired. If the fair value of the asset is less than the carrying amount, we perform a quantitative test to determine the fair value. The impairment loss, if any, is

measured as the excess of the carrying value of the asset over its fair value. The fair value of the indefinite-lived intangibles exceeded their carrying values at December 31, 2015. We will continue to closely monitor the performance of our indefinite-lived intangible assets. There can be no assurance that future events will not result in an impairment of indefinite-lived intangible assets.

Our long-lived assets are carried on our financial statements based on their cost less accumulated depreciation or amortization. Long-lived assets with finite lives are reviewed for impairment whenever events or changes in circumstances indicate that their carrying value may not be entirely recoverable. When such factors and circumstances exist, management compares the projected undiscounted future cash flows associated with the related asset or group of assets over their estimated useful lives against their respective carrying amounts. The impairment loss, if any, is measured as the excess of the carrying amount over the fair value of the asset and is recorded in the period in which the determination is made. Any resulting impairment losses recorded by us could have an adverse impact on our results of operations.

In 2015 and in response to the same circumstances which triggered the goodwill impairment charges recognized relative to the Oil and Gas Field Services segment, we performed analyses to consider whether the carrying values of other long-lived assets held within the segment may not be entirely recoverable. As of December 31, 2015, the Oil and Gas Field Services segment had property, plant and equipment, net of $156.3 million, other intangible assets of $14.9 million consisting of customer and supplier relationships of $8.2 million and other intangible assets of $6.7 million. As a result of these analyses, we concluded that no impairment of intangible or other long lived assets existed as estimated cash flows generated from associated asset groups exceeded their carrying values.

We will continue to evaluate all of our goodwill and other long-lived assets impacted by economic downturns most predominantly in oil and energy related markets in which they operate. If further economic difficulties resulting from depressed oil and gas related pricing and lower overall activity levels, particularly in our Canadian operations, continue for a significant foreseeable period of time and thus future operating results are significantly less than current expectations additional impairment charges may be recognized. The market conditions which could lead to such future impairments are currently most prevalent in our Oil and Gas Field Services, Lodging Services and Industrial Services operations.

Legal Matters. As described in Note 16, "Commitments and Contingencies," to our consolidated financial statements included in Item 8 of this report, we are subject to legal proceedings which relate to our past acquisitions or which have arisen in the ordinary course of business. Accruals are established for legal matters when, in our opinion, it is probable that a liability exists and the liability can be reasonably estimated. As of December 31, 2015, we had reserves of $21.9 million consisting of (i) $18.9 million related to pending legal or administrative proceedings, including Superfund liabilities, which were included in the $188.2 million accrued environmental liabilities as of December 31, 2015 for closure, post-closure and remediation as described above, and (ii) $3.0 million primarily related to federal and state enforcement actions, which were included in accrued expenses on the consolidated balance sheets. We also estimate that it is "reasonably possible," as that term is defined ("more than remote but less than likely"), that the amount of such total liabilities could be as much as $1.9 million more. Actual expenses incurred in future periods could differ materially from accruals established.

Provision for Income Taxes. Our income tax expense, deferred tax assets and liabilities and reserves for unrecognized tax benefits reflect management's best estimate of future taxes to be paid. We are subject to income taxes in both the United States and in foreign jurisdictions. Significant judgments and estimates are required in determining the consolidated income tax expense. We do not accrue U.S. tax for foreign earnings that we consider to be permanently reinvested outside the United States. Consequently, we have not provided any U.S. tax on the unremitted earnings of our foreign subsidiaries. As of December 31, 2015, the amount of earnings for which no repatriation tax has been provided was $212.7 million. It is not practicable to estimate the amount of additional tax that might be payable on those earnings if repatriated.

Deferred income taxes arise from temporary differences between the tax and financial statement recognition of revenue and expense. In evaluating our ability to recover our deferred tax assets within the jurisdiction from which they arise, we consider all available positive and negative evidence. We establish a valuation allowance when, based on an evaluation of objective verifiable evidence, we believe it is more likely than not that some portion or all of deferred tax assets will not be realized.

A liability for uncertain tax positions is recorded to the extent a tax position taken or expected to be taken in a tax return does not meet certain recognition or measurement criteria. We record interest and penalties on these uncertain tax positions as applicable as a component of income tax expense.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

In the normal course of business, we are exposed to market risks, including changes in interest rates and certain foreign currency rates, primarily the Canadian dollar. Our philosophy in managing interest rate risk is to borrow at fixed rates for longer time horizons to finance non-current assets and to borrow (to the extent, if any, required) at variable rates for working capital and other short-term needs. We therefore have not entered into derivative or hedging transactions relating to interest rate risk, nor have we entered into transactions to finance off-balance sheet debt. The following table provides information regarding our fixed rate borrowings at December 31, 2015 (in thousands):

Scheduled Maturity Dates	2016	2017	2018	2019	2020	Thereafter	Total
Senior unsecured notes due 2020	$ —	$ —	$ —	$ —	$ 800,000	$ —	$ 800,000
Senior unsecured notes due 2021	—	—	—	—	—	595,000	595,000
Long term obligations, at par	$ —	$ —	$ —	$ —	$ 800,000	$ 595,000	$ 1,395,000
Weighted average interest rate on fixed rate borrowings							5.2%

In addition to the fixed rate borrowings described in the above table, we had at December 31, 2015, variable rate instruments that included a revolving credit facility with maximum borrowings of up to $400.0 million (with a $325.0 million sub-limit for letters of credit). Interest payments are due in the amount of $21.0 million each related to the $800.0 million senior unsecured notes payable semi-annually on February 1 and August 1 of each year, and in the amount of $15.2 million each related to the $595.0 million senior unsecured notes payable semi-annually on June 1 and December 1 of each year.

We view our investment in our foreign subsidiaries as long-term; thus, we have not entered into any hedging transactions between any two foreign currencies or between any of the foreign currencies and the U.S. dollar. During 2015, the Canadian subsidiaries transacted approximately 10.8% of their business in U.S. dollars and at any period end have cash on deposit in U.S. dollars and outstanding U.S. dollar accounts receivable related to these transactions. These cash and receivable accounts are vulnerable to foreign currency transaction gains or losses. Exchange rate movements also affect the translation of Canadian generated profits and losses into U.S. dollars. Had the Canadian dollar been 10.0% stronger or weaker against the U.S. dollar, we would have reported increased or decreased net income of $6.5 million and $2.6 million for the year ended December 31, 2015 and 2014, respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Clean Harbors, Inc.
Norwell, Massachusetts

We have audited the accompanying consolidated balance sheets of Clean Harbors, Inc. and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income (loss), comprehensive (loss) income, cash flows and stockholders' equity for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Clean Harbors, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Boston, Massachusetts
February 25, 2016

CLEAN HARBORS, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(dollars in thousands)

	As of December 31,	
	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 184,708	$ 246,879
Accounts receivable, net of allowances aggregating $31,426 and $25,661, respectively	496,004	557,131
Unbilled accounts receivable	25,940	40,775
Deferred costs	18,758	19,018
Inventories and supplies	149,521	168,663
Prepaid expenses and other current assets	46,265	57,435
Deferred tax assets	—	36,532
Total current assets	921,196	1,126,433
Property, plant and equipment, net	1,532,467	1,558,834
Other assets:		
Deferred financing costs	1,847	2,725
Goodwill	453,105	452,669
Permits and other intangibles, net	506,818	530,080
Other	15,995	18,682
Total other assets	977,765	1,004,156
Total assets	$ 3,431,428	$ 3,689,423
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Current portion of capital lease obligations	$ —	$ 536
Accounts payable	241,183	267,329
Deferred revenue	61,882	62,966
Accrued expenses	193,660	219,549
Current portion of closure, post-closure and remedial liabilities	20,395	22,091
Total current liabilities	517,120	572,471
Other liabilities:		
Closure and post-closure liabilities, less current portion of $7,229 and $4,999, respectively	49,020	45,702
Remedial liabilities, less current portion of $13,166 and $17,092, respectively	118,826	138,029
Long-term obligations	1,382,543	1,380,145
Deferred taxes, unrecognized tax benefits and other long-term liabilities	267,637	290,205
Total other liabilities	1,818,026	1,854,081
Commitments and contingent liabilities (See Note 16)		
Stockholders' equity:		
Common stock, $.01 par value:		
Authorized 80,000,000 shares; issued and outstanding 57,593,201 and 58,903,482 shares, respectively	576	589
Shares held under employee participation plan	(469)	(469)
Additional paid-in capital	738,401	805,029
Accumulated other comprehensive loss	(254,892)	(110,842)
Accumulated earnings	612,666	568,564
Total stockholders' equity	1,096,282	1,262,871
Total liabilities and stockholders' equity	$ 3,431,428	$ 3,689,423

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

CLEAN HARBORS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (LOSS)
(in thousands except per share amounts)

	For the years ended December 31,		
	2015	2014	2013
Revenues:			
Service revenues	$ 2,744,272	$ 2,639,796	$ 2,729,205
Product revenues	530,865	761,840	780,451
Total revenues	3,275,137	3,401,636	3,509,656
Cost of revenues: (exclusive of items shown separately below)			
Service revenues	1,898,907	1,790,377	1,874,448
Product revenues	457,899	651,419	668,185
Total cost of revenues	2,356,806	2,441,796	2,542,633
Selling, general and administrative expenses	414,164	437,921	470,477
Accretion of environmental liabilities	10,402	10,612	11,541
Depreciation and amortization	274,194	276,083	264,449
Goodwill impairment charge	31,992	123,414	—
Income from operations	187,579	111,810	220,556
Other (expense) income	(1,380)	4,380	1,705
Interest expense, net of interest income of $626, $819, and $507, respectively	(76,553)	(77,668)	(78,376)
Income before provision for income taxes	109,646	38,522	143,885
Provision for income taxes	65,544	66,850	48,319
Net income (loss)	$ 44,102	$ (28,328)	$ 95,566
Earnings (loss) per share:			
Basic	$ 0.76	$ (0.47)	$ 1.58
Diluted	$ 0.76	$ (0.47)	$ 1.57
Shares used to compute earnings (loss) per share — Basic	58,324	60,311	60,574
Shares used to compute earnings (loss) per share — Diluted	58,434	60,311	60,728

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

CLEAN HARBORS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME
(in thousands)

	For the years ended December 31,		
	2015	2014	2013
Net income (loss)	$ 44,102	$ (28,328)	$ 95,566
Other comprehensive loss:			
Unrealized gains on available-for-sale securities (net of taxes of $0, $183 and $208, respectively)	—	976	1,244
Reclassification adjustment for gains on available-for-sale securities included in net income (net of taxes of $508)	—	(2,880)	—
Foreign currency translation adjustments	(144,050)	(88,725)	(70,791)
Unfunded pension liability (net of taxes of $7, $248 and $123, respectively)	—	(657)	359
Other comprehensive loss	(144,050)	(91,286)	(69,188)
Comprehensive (loss) income	$ (99,948)	$ (119,614)	$ 26,378

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

Table Of Contents

CLEAN HARBORS, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	For the years ended December 31,		
	2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$ 44,102	$ (28,328)	$ 95,566
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	274,194	276,083	264,449
Goodwill impairment charge	31,992	123,414	—
Pre-tax, non-cash acquisition accounting inventory adjustments	—	—	13,559
Allowance for doubtful accounts	4,793	8,917	7,933
Amortization of deferred financing costs and debt discount	3,280	3,289	3,301
Accretion of environmental liabilities	10,402	10,612	11,541
Changes in environmental liability estimates	(11,345)	(3,367)	(3,682)
Deferred income taxes	1,930	32,320	31,119
Other expense (income)	1,380	(4,380)	(1,705)
Stock-based compensation	8,550	8,800	8,946
Excess tax benefit of stock-based compensation	(71)	(878)	(1,409)
Net tax benefit on stock-based awards	(82)	816	1,399
Environmental expenditures	(20,130)	(20,245)	(19,416)
Changes in assets and liabilities:			
Accounts receivable and unbilled accounts receivables	55,271	(14,342)	(54,213)
Inventories and supplies	14,059	(21,339)	(1,144)
Other current assets	48,760	(19,030)	20,857
Accounts payable	(16,299)	(52,026)	37,117
Other current and long-term liabilities	(54,403)	(2,950)	1,621
Net cash from operating activities	396,383	297,366	415,839
Cash flows used in investing activities:			
Additions to property, plant and equipment	(257,196)	(257,613)	(280,207)
Proceeds from sales of fixed assets	6,195	8,164	4,699
Acquisitions, net of cash acquired	(94,345)	(16,187)	(63,264)
Additions to intangible assets including costs to obtain or renew permits	(5,296)	(6,519)	(6,740)
Proceeds from sales of investments	—	13,861	—
Other	—	—	—
Net cash used in investing activities	(350,642)	(258,294)	(345,512)
Cash flows (used in) from financing activities:			
Change in uncashed checks	(14,630)	15,069	12,268
Proceeds from exercise of stock options	397	—	400
Remittance of shares, net	(2,159)	(2,793)	(731)
Repurchases of common stock	(73,347)	(104,341)	—
Excess tax benefit of stock-based compensation	71	878	1,409
Deferred financing costs paid	—	—	(2,504)
Repayment of long-term obligations	—	(5,000)	—
Proceeds from employee stock purchase plan	—	4,364	7,425
Payments on capital leases	(511)	(2,122)	(4,891)
Issuance costs related to issuances of common stock	—	—	(250)
Net cash (used in) from financing activities	(90,179)	(93,945)	13,126
Effect of exchange rate change on cash	(17,733)	(8,321)	(3,216)
(Decrease) increase in cash and cash equivalents	(62,171)	(63,194)	80,237
Cash and cash equivalents, beginning of year	246,879	310,073	229,836
Cash and cash equivalents, end of year	$ 184,708	$ 246,879	$ 310,073
Supplemental information:			
Cash payments for interest and income taxes:			
Interest paid	$ 73,926	$ 75,408	$ 75,627
Income taxes paid (received)	52,970	42,022	(8,162)
Non-cash investing and financing activities:			

Property, plant and equipment accrued	32,677	23,563	33,214
Transfer of inventory to property, plant and equipment	—	1,324	11,369
Accrued business combination adjustments	—	355	—
Receivable for estimated purchase price adjustment	1,000	—	—

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

CLEAN HARBORS, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Stock		Shares Held Under Employee Participation Plan	Additional Paid-in Capital	Accumulated Other Comprehensive Income (loss)	Accumulated Earnings	Total Stockholders' Equity
	Number of Shares	$0.01 Par Value					
Balance at January 1, 2013	60,385	$ 604	$ (469)	$ 880,979	$ 49,632	$ 501,326	$ 1,432,072
Net income	—	—	—	—	—	95,566	95,566
Other comprehensive income	—	—	—	—	(69,188)	—	(69,188)
Stock-based compensation	74	—	—	8,946	—	—	8,946
Issuance of restricted shares, net of shares remitted	(19)	—	—	(731)	—	—	(731)
Issuance of common stock, net of issuance cost	—	—	—	(250)	—	—	(250)
Exercise of stock options	61	3	—	397	—	—	400
Net tax benefit on stock-based awards	—	—	—	1,399	—	—	1,399
Employee stock purchase plan	171	—	—	7,425	—	—	7,425
Balance at December 31, 2013	60,672	$ 607	$ (469)	$ 898,165	$ (19,556)	$ 596,892	$ 1,475,639
Net loss	—	—	—	—	—	(28,328)	(28,328)
Other comprehensive loss	—	—	—	—	(91,286)	—	(91,286)
Stock-based compensation	—	—	—	8,800	—	—	8,800
Issuance of restricted shares, net of shares remitted	113	1	—	(2,794)	—	—	(2,793)
Repurchases of common stock	(1,973)	(20)	—	(104,321)	—	—	(104,341)
Net tax benefit on stock-based awards	—	—	—	816	—	—	816
Employee stock purchase plan	91	1	—	4,363	—	—	4,364
Balance at December 31, 2014	58,903	$ 589	$ (469)	$ 805,029	$ (110,842)	$ 568,564	$ 1,262,871
Net income	—	—	—	—	—	44,102	44,102
Other comprehensive loss	—	—	—	—	(144,050)	—	(144,050)
Stock-based compensation	—	—	—	8,550	—	—	8,550
Issuance of restricted shares, net of shares remitted	100	1	—	(2,160)	—	—	(2,159)
Exercise of stock options	12	—	—	397	—	—	397
Repurchases of common stock	(1,422)	(14)	—	(73,333)	—	—	(73,347)
Net tax benefit on stock-based awards	—	—	—	(82)	—	—	(82)
Balance at December 31, 2015	57,593	$ 576	$ (469)	$ 738,401	$ (254,892)	$ 612,666	$ 1,096,282

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

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) OPERATIONS

Clean Harbors, Inc., through its subsidiaries (collectively, the "Company"), is a leading provider of environmental, energy and industrial services throughout North America.

(2) SIGNIFICANT ACCOUNTING POLICIES

The accompanying consolidated financial statements of the Company reflect the application of certain significant accounting policies as described below:

Principles of Consolidation

The accompanying consolidated statements include the accounts of Clean Harbors, Inc. and its majority-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions, which are evaluated on an ongoing basis, that affect the amounts reported in the Company's consolidated financial statements and accompanying notes. Management bases its estimates on historical experience and on various other assumptions it believes to be reasonable at the time under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities and disclosure, if any, of contingent assets and liabilities and reported amounts of revenues and expenses. Actual results could differ from those estimates and judgments.

Reclassifications

As a result of the adoption of new accounting pronouncements issued in 2015 and discussed further in Note 2 under the heading *Recent Accounting Pronouncements*, certain balance sheets amounts previously reported in prior period financial statements have been reclassified in accordance with the implemented standards.

Fair Value Valuation Hierarchy

The Company defines fair value 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 the measurement date. The Company applies the following fair value hierarchy, which prioritizes the inputs used to measure fair value into three levels and bases the categorization within the hierarchy upon the lowest level of input that is available and significant to the fair value measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. Level 2 utilizes quoted market prices in markets that are not active, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Level 3 inputs are unobservable inputs for the asset or liability in which there is little, if any, market activity for the asset or liability at the measurement date.

The Company's financial instruments consist of cash and cash equivalents, accounts and unbilled receivable, accounts payable and accrued liabilities and long-term debt obligations. Due to the short-term nature of these instruments, with the exception of long-term debt obligations, their estimated fair value approximates carrying value. Senior unsecured notes are recorded at par.

Cash, Cash Equivalents and Uncashed Checks

Cash and cash equivalents consist primarily of cash on deposit, money market accounts or short-term investments with original maturities of three months or less. The fair value of our cash equivalents is considered a Level 1 measure according to the fair value hierarchy and is adjusted to fair value based on quoted market prices. The Company's cash management program with its revolving credit lender allows for the maintenance of a zero balance in the U.S. bank disbursement accounts that are used to issue vendor and payroll checks. The program can result in checks outstanding in excess of bank balances in the disbursement accounts. When checks are presented to the bank for payment, cash deposits in amounts sufficient to fund the

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

checks are made, at the Company's discretion, either from funds provided by other accounts or under the terms of the Company's revolving credit facility. Therefore, until checks are presented for payment, there is no right of offset by the bank and the Company continues to have control over cash relating to both released as well as unreleased checks. Checks that have been written to vendors or employees but have not yet been presented for payment at the Company's bank are classified as uncashed checks as part of accounts payable and added back to cash balances.

Marketable Securities

The Company has classified its marketable securities as available-for-sale and, accordingly, carries such securities at fair value. Unrealized gains and losses are reported, net of tax, as a component of other comprehensive income.

Allowances for Doubtful Accounts

On a regular basis, the Company evaluates its accounts receivable and establishes the allowance for doubtful accounts based on an evaluation of historical collection trends, customer concentration, customer credit ratings, current economic trends and changes in customer payment patterns. Past-due receivable balances are written-off when the Company's internal collection efforts have been deemed unsuccessful in collecting the outstanding balance due.

Credit Concentration

Concentration of credit risks in accounts receivable is limited due to the large number of customers comprising the Company's customer base throughout North America. The Company maintains policies over credit extension that include credit evaluations, credit limits and collection monitoring procedures on a customer-by-customer basis. However, the Company generally does not require collateral before services are performed. As of December 31, 2015 and 2014, no individual customer accounted for more than 10% of accounts receivable. During each of the years ended December 31, 2015, 2014 and 2013, no individual customer accounted for more than 10% of total revenues.

Unbilled Receivables

The Company recognizes unbilled accounts receivable for service and disposal transactions rendered but not invoiced to the customer by the end of the period.

Deferred Costs Relating to Deferred Revenue

Commissions and other incremental direct costs, primarily costs of materials, relating to deferred revenue from the Company’s parts cleaning services, containerized waste services and vacuum services are capitalized and deferred. The deferred costs are included in current assets in the consolidated balance sheet and charged to expense when the related revenues are recognized.

Inventories and Supplies

Inventories are stated at the lower of cost or market. The cost of oil and oil products is principally determined on a first-in, first-out ("FIFO") basis. The cost of supplies and drums, solvent and solution and other inventories is determined on a FIFO or a weighted average cost basis. Costs for oil and oil products, solvent and repair parts include purchase costs, fleet and fuel costs, direct labor, transportation costs and production related costs. The Company continually reviews its inventories for obsolete or unsalable items and adjusts its carrying value to reflect estimated realizable values.

Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consist primarily of prepayments for various services, refundable deposits, and income taxes receivable.

Property, Plant and Equipment (excluding landfill assets)

Property, plant and equipment are stated at cost and include amounts capitalized under capital lease obligations. Expenditures for major renewals and improvements which extend the life or usefulness of the asset are capitalized. Items of an ordinary repair or maintenance nature are charged directly to operating expense as incurred. During the construction and development period of an asset, the costs incurred, including applicable interest costs, are classified as construction-in-progress.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

The Company depreciates and amortizes the cost of these assets, using the straight-line method as follows:

Asset Classification	Estimated Useful Life
Buildings and building improvements	
Buildings	30–40 years
Leasehold and building improvements	2–40 years
Camp equipment	8–15 years
Vehicles	3–12 years
Equipment	
Capitalized software and computer equipment	3–5 years
Solar equipment	20 years
Containers and railcars	15–20 years
All other equipment	8–20 years
Furniture and fixtures	5–8 years

Leasehold and building improvements have a weighted average life of 10.2 years.

Camp equipment consists of industrial lodging facilities that are utilized to provide lodging services to downstream oil and gas companies in Western Canada.

Solar equipment consists of a solar array that is used to provide electric power for a continuously operating groundwater decontamination pump and treatment system at a closed and capped landfill located in New Jersey.

The Company recognizes an impairment in the carrying value of long-lived assets when the expected future undiscounted cash flows derived from the assets, or group of assets, are less than their carrying value. For the years ended December 31, 2015, 2014 and 2013, the Company did not record impairment charges related to long-lived assets. The Company will continue to assess all of its long-lived assets for impairment as necessary.

Goodwill

Goodwill is comprised of the purchase price of business acquisitions in excess of the fair value assigned at acquisition to the net tangible and identifiable intangible assets acquired. Goodwill is not amortized but is reviewed for impairment annually as of December 31, or when events or changes in the business environment indicate that the carrying value of the reporting unit may exceed its fair value, by comparing the fair value of each reporting unit to its carrying value, including goodwill. If the fair value is less than the carrying amount, a Step II goodwill impairment test is performed to determine if goodwill is impaired. The loss, if any, is measured as the excess of the carrying value of the goodwill over the implied value of the goodwill. See Note 6, "Goodwill and Other Intangible Assets," for additional information related to the Company's goodwill impairment tests and the goodwill impairment charges recorded in 2015 and 2014.

Permits and other intangibles

Permits and intangible assets, such as legal fees, site surveys, engineering costs and other expenditures are recorded as cost. Other intangible assets consist primarily of customer and supplier relationships, trademarks and trade names, and non-compete agreements. Permits relating to landfills are amortized on a units-of-consumption basis. All other permits are amortized over periods ranging from 5 to 30 years on a straight-line basis. Other intangible assets are amortized on a straight-line basis over their respective useful lives, which range from 2 to 20 years.

Finite-lived intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying value may not be entirely recoverable. When such factors and circumstances exist, management compares the projected undiscounted future cash flows associated with the related asset or group of assets over their estimated useful lives against their respective carrying amounts. The impairment loss, if any, is measured as the excess of the carrying amount over the fair value of the asset or group of assets.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

Indefinite-lived intangible assets are not amortized but are reviewed for impairment annually as of December 31, or when events or changes in the business environment indicate that the carrying value may be impaired. If the fair value of the asset is less than the carrying amount, the Company performs a quantitative test to determine the fair value. The impairment loss, if any,
is measured as the excess of the carrying value of the asset over its fair value. The fair value of the indefinite-lived intangible assets exceeded their carrying values at December 31, 2015 and 2014.

Leases

The Company leases rolling stock, rail cars, equipment, real estate and office equipment under operating leases. Certain real estate leases contain rent holidays and rent escalation clauses. Most of the Company's real estate lease agreements include renewal periods at the Company's option. For its operating leases, the Company recognizes rent holiday periods and scheduled rent increases on a straight-line basis over the lease term beginning with the date the Company takes possession of the leased assets.

Landfill Accounting

The Company amortizes landfill improvements, and certain landfill-related permits over their estimated useful lives. The units-of-consumption method is used to amortize land, landfill cell construction, asset retirement costs and remaining landfill cells and sites. The Company also utilizes the units-of-consumption method to record closure and post-closure obligations for landfill cells and sites. Under the units-of-consumption method, the Company includes future estimated construction and asset retirement costs, as well as costs incurred to date, in the amortization base of the landfill assets. Additionally, where appropriate, as described below, the Company includes probable expansion airspace that has yet to be permitted in the calculation of the total remaining useful life of the landfill. If it is determined that expansion capacity should no longer be considered in calculating the recoverability of a landfill asset, the Company may be required to recognize an asset impairment or incur significantly higher amortization expense. If at any time the Company makes the decision to abandon the expansion effort, the capitalized costs related to the expansion effort are expensed immediately.

Landfill assets—Landfill assets include the costs of landfill site acquisition, permits and cell construction incurred to date. These amounts are recorded at cost, which includes capitalized interest as applicable. Landfill assets, net of amortization, are combined with management's estimate of the costs required to complete construction of the landfill to determine the amount to be amortized over the remaining estimated useful economic life of a site. Amortization of landfill assets is recorded on a units-of-consumption basis, such that the landfill assets should be completely amortized at the date the landfill ceases accepting waste. Amortization totaled $11.2 million, $14.1 million and $16.8 million for the years ended December 31, 2015, 2014 and 2013, respectively. Changes in estimated costs to complete construction are applied prospectively to the amortization rate.

Landfill capacity—Landfill capacity, which is the basis for the amortization of landfill assets and for the accrual of final closure and post-closure obligations, represents total permitted airspace plus unpermitted airspace that management believes is probable of ultimately being permitted based on established criteria. The Company applies the following criteria for evaluating the probability of obtaining a permit for future expansion airspace at existing sites, which provides management a basis to evaluate the likelihood of success of unpermitted expansions:

- Personnel are actively working to obtain the permit or permit modifications (land use, state, provincial and federal) necessary for expansion of an existing landfill, and progress is being made on the project.
- Management expects to submit the application within the next year and to receive all necessary approvals to accept waste within the next 5 years.
- At the time the expansion is included in the Company's estimate of the landfill's useful economic life, it is probable that the required approvals will be received within the normal application and processing time periods for approvals in the jurisdiction in which the landfill is located.
- The Company or other owner of the landfill has a legal right to use or obtain the right to use the land associated with the expansion plan.
- There are no significant known political, technical, legal or business restrictions or issues that could impair the success of such expansion.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

- A financial feasibility analysis has been completed and the results demonstrate that the expansion will have a positive financial and operational impact such that management is committed to pursuing the expansion.

- Additional airspace and related additional costs, including permitting, final closure and post-closure costs, have been estimated based on the conceptual design of the proposed expansion.

As of December 31, 2015, there was one unpermitted expansion at one location included in the Company's landfill accounting model, which represented 3.0% of the Company's remaining airspace at that date. If actual expansion airspace is significantly different from the Company's estimate of expansion airspace, the amortization rates used for the units-of-consumption method would change, therefore impacting the Company's profitability. If the Company determines that there is less actual expansion airspace at a landfill, this would increase amortization expense recorded and decrease profitability, while if the Company determines a landfill has more actual expansion airspace, amortization expense would decrease and profitability would increase.

As of December 31, 2015, the Company had 11 active landfill sites (including the Company's two non-commercial landfills), which have estimated remaining lives (based on anticipated waste volumes and remaining highly probable airspace) as follows:

Facility Name	Location	Remaining Lives (Years)	Remaining Highly Probable Airspace (cubic yards) (in thousands)		
			Permitted	Unpermitted	Total
Altair	Texas	6	686	—	686
Buttonwillow	California	20	7,023	—	7,023
Deer Park	Texas	7	268	—	268
Deer Trail	Colorado	28	1,932	—	1,932
Grassy Mountain	Utah	20	1,839	—	1,839
Kimball	Nebraska	9	243	—	243
Lambton	Ontario	37	5,062	—	5,062
Lone Mountain	Oklahoma	32	4,809	—	4,809
Ryley	Alberta	9	608	880	1,488
Sawyer	North Dakota	45	3,704	—	3,704
Westmorland	California	64	2,732	—	2,732
			28,906	880	29,786

At December 31, 2015 and 2014, the Company had no cubic yards of permitted, but not highly probable, airspace.

The following table presents the remaining highly probable airspace from January 1, 2013 through December 31, 2015 (in thousands of cubic yards):

	2015	2014	2013
Remaining capacity at January 1,	30,544	29,323	29,643
Addition of highly probable airspace, net	516	2,809	1,218
Consumed	(1,274)	(1,588)	(1,538)
Remaining capacity at December 31,	29,786	30,544	29,323

Amortization of cell construction costs and accrual of cell closure obligations—Landfills are typically comprised of a number of cells, which are constructed within a defined acreage (or footprint). The cells are typically discrete units, which require both separate construction and separate capping and closure procedures. Cell construction costs are the costs required to excavate and construct the landfill cell. These costs are typically amortized on a units-of-consumption basis, such that they are completely amortized when the specific cell ceases accepting waste. In some instances, the Company has landfills that are engineered and constructed as "progressive trenches." In progressive trench landfills, a number of contiguous cells form a progressive trench. In those instances, the Company amortizes cell construction costs over the airspace within the entire trench, such that the cell construction costs will be fully amortized at the end of the trench useful life.

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

The design and construction of a landfill does not create a landfill asset retirement obligation. Rather, the asset retirement obligation for cell closure (the cost associated with capping each cell) is incurred in relatively small increments as waste is placed in the landfill. Therefore, the cost required to construct the cell cap is capitalized as an asset retirement cost and a liability of an equal amount is established, based on the discounted cash flow associated with each capping event, as airspace is consumed. Spending for cell capping is reflected as environmental expenditures within operating activities in the statement of cash flows.

Landfill final closure and post-closure liabilities—The balance of landfill final closure and post-closure liabilities at December 31, 2015 and 2014 was $32.0 million and $29.9 million, respectively. The Company has material financial commitments for the costs associated with requirements of the Environmental Protection Agency ("EPA") and the comparable regulatory agency in Canada for landfill final closure and post-closure activities. In the United States, the landfill final closure and post-closure requirements are established under the standards of the EPA, and are implemented and applied on a state-by-state basis. The Company develops estimates for the cost of these activities based on an evaluation of site-specific facts and circumstances, including the Company's interpretation of current regulatory requirements and proposed regulatory changes. Such estimates may change in the future due to various circumstances including, but not limited to, permit modifications, changes in legislation or regulations, technological changes and results of environmental studies.

Final closure costs are the costs incurred after the site ceases to accept waste, but before the landfill is certified as closed by the applicable state regulatory agency. These costs generally include the costs required to cap the final cell of the landfill (if not included in cell closure), the costs required to dismantle certain structures for landfills and other landfill improvements, and regulation-mandated groundwater monitoring, and leachate management. Post-closure costs involve the maintenance and monitoring of a landfill site that has been certified closed by the applicable regulatory agency. These costs generally include groundwater monitoring and leachate management. Regulatory post-closure periods are generally 30 years after landfill closure. Final closure and post-closure obligations are accrued on a units-of-consumption basis, such that the present value of the final closure and post-closure obligations are fully accrued at the date the landfill discontinues accepting waste.

Cell closure, final closure and post closure costs (also referred to as "asset retirement obligations") are calculated by estimating the total obligation in current dollars, adjusted for inflation (1.02% during 2015 and 2014) and discounted at the Company's credit-adjusted risk-free interest rate (5.99% and 6.54% during 2015 and 2014, respectively.)

Non-Landfill Closure and Post-Closure Liabilities

Non-landfill closure costs include costs required to dismantle and decontaminate certain structures and other costs incurred during the closure process. Post-closure costs, if required, include associated maintenance and monitoring costs as required by the closure permit. Post-closure periods are performance-based and are not generally specified in terms of years in the closure permit, but generally range from 10 to 30 years or more.

The Company records its non-landfill closure and post-closure liability by: (i) estimating the current cost of closing a non-landfill facility and the post-closure care of that facility, if required, based upon the closure plan that the Company is required to follow under its operating permit, or in the event the facility operates with a permit that does not contain a closure plan, based upon legally enforceable closure commitments made by the Company to various governmental agencies; (ii) using probability scenarios as to when in the future operations may cease; (iii) inflating the current cost of closing the non-landfill facility on a probability weighted basis using the inflation rate to the time of closing under each probability scenario; and (iv) discounting the future value of each closing scenario back to the present using the credit-adjusted risk-free interest rate. Non-landfill closure and post-closure obligations arise when the Company commences operations.

The balance of non-landfill closure and post-closure liabilities at December 31, 2015 and 2014 was $24.2 million and $20.8 million, respectively. Management bases estimates for non-landfill closure and post-closure liabilities on its interpretation of existing permit and regulatory requirements for closure and post-closure maintenance and monitoring. The Company's cost estimates are calculated using internal sources as well as input from third party experts. Management uses probability scenarios to estimate when future operations will cease and inflates the current cost of closing the non-landfill facility on a probability weighted basis using the appropriate inflation rate and then discounting the future value to arrive at an estimated present value of closure and post-closure costs. The estimates for non-landfill closure and post-closure liabilities are inherently uncertain due to the possibility that permit and regulatory requirements will change in the future, impacting the estimation of total costs and the timing of the expenditures. Management reviews non-landfill closure and post-closure liabilities for changes to key assumptions that would impact the amount of the recorded liabilities. Changes that would prompt management to revise a liability estimate include changes in legal requirements that impact the Company's expected closure plan or scope of work, in

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

the market price of a significant cost item, in the probability scenarios as to when future operations at a location might cease, or in the expected timing of the cost expenditures. Changes in estimates for non-landfill closure and post-closure events immediately impact the required liability and the value of the corresponding asset. If a change is made to a fully-consumed asset, the adjustment is charged immediately to expense. When a change in estimate relates to an asset that has not been fully consumed, the adjustment to the asset is recognized in income prospectively as a component of amortization. Historically, material changes to non-landfill closure and post-closure estimates have been infrequent.

Remedial Liabilities

The balance of remedial liabilities at December 31, 2015 and 2014 was $132.0 million and $155.1 million, respectively. Remedial liabilities, including Superfund liabilities, include the costs of removal or containment of contaminated material, treatment of potentially contaminated groundwater and maintenance and monitoring costs necessary to comply with regulatory requirements. Most of the Company's remedial liabilities relate to the active and inactive hazardous waste treatment and disposal facilities which the Company acquired in the last 14 years and 35 Superfund sites owned by third parties for which the Company agreed to indemnify certain remedial liabilities owed or potentially owed to governmental entities by the sellers of certain assets (the "CSD assets") which the Company acquired in 2002. The Company performed extensive due diligence to estimate accurately the aggregate liability for remedial liabilities to which the Company became potentially liable as a result of the acquisitions. The Company's estimate of remedial liabilities involved an analysis of such factors as: (i) the nature and extent of environmental contamination (if any); (ii) the terms of applicable permits and agreements with regulatory authorities as to cleanup procedures and whether modifications to such permits and agreements will likely need to be negotiated; (iii) the cost of performing anticipated cleanup activities based upon current technology; and (iv) in the case of Superfund and other sites where other parties will also be responsible for a portion of the cleanup costs, the likely allocation of such costs and the ability of such other parties to pay their share. Remedial liabilities and on-going operations are reviewed quarterly and adjustments are made as necessary.

The Company periodically evaluates potential remedial liabilities at sites that it owns or operates or to which the Company or the sellers of the CSD assets (or the respective predecessors of the Company or such sellers) transported or disposed of waste, including 128 Superfund sites as of December 31, 2015. The Company periodically reviews and evaluates sites requiring remediation, including Superfund sites, giving consideration to the nature (i.e., owner, operator, arranger, transporter or generator) and the extent (i.e., amount and nature of waste hauled to the location, number of years of site operations or other relevant factors) of the Company's (or such sellers') alleged connection with the site, the extent (if any) to which the Company believes it may have an obligation to indemnify cleanup costs in connection with the site, the regulatory context surrounding the site, the accuracy and strength of evidence connecting the Company (or such sellers) to the location, the number, connection and financial ability of other named and unnamed potentially responsible parties ("PRPs") and the nature and estimated cost of the likely remedy. Where the Company concludes that it is probable that a liability has been incurred and an amount can be estimated, a provision is made, based upon management's judgment and prior experience, of such estimated liability.

Remedial liabilities are inherently difficult to estimate. Estimating remedial liabilities requires that the existing environmental contamination be understood. There are risks that the actual quantities of contaminants differ from the results of the site investigation, and that contaminants exist that have not been identified by the site investigation. In addition, the amount of remedial liabilities recorded is dependent on the remedial method selected. There is a risk that funds will be expended on a remedial solution that is not successful, which could result in the additional incremental costs of an alternative solution. Such estimates, which are subject to change, are subsequently revised if and when additional or new information becomes available.

Remedial liabilities are discounted only when the timing of the payments is estimable and the amounts are determinable. Management's experience has been that the timing of payments for remedial liabilities is not usually estimable, and therefore the amounts of remedial liabilities are not generally discounted. In the case of remedial liabilities assumed in connection with acquisitions, acquired liabilities are recorded under purchase accounting at fair value. Accordingly, as of the respective acquisition dates, the Company recorded the remedial liabilities assumed as part of acquisitions at their fair value, which were calculated by inflating costs in current dollars using an estimate of future inflation rates as of the respective acquisition dates until the expected time of payment, and then discounting the amount of the payments to their present value using a risk-free discount rate as of the acquisition dates. Discounts were and will be applied to the environmental liabilities as follows:

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

- Remedial liabilities assumed relating to acquisitions are and will continue to be inflated using the inflation rates at the time of each acquisition (ranging from 1.01% to 2.57%) until the expected time of payment, then discounted at the risk-free interest rate at the time of such acquisition (ranging from 2.88% to 5.99%).
- Remedial liabilities incurred subsequent to the acquisitions and remedial liabilities of the Company that existed prior to the acquisitions have been and will continue to be recorded at the estimated current value of the liabilities, which is usually neither increased for inflation nor reduced for discounting.

Foreign Currency

During the year ended December 31, 2015 and 2014, the Company had operations in Canada, and to a much lesser extent, Mexico and Trinidad. Assets and liabilities are translated to U.S. dollars at the exchange rate in effect at the balance sheet date and revenue and expenses at the average exchange rate for the period. Gains and losses from the translation of the consolidated financial statements of foreign subsidiaries into U.S. dollars are included in stockholders' equity as a component of accumulated other comprehensive income. Gains and losses resulting from foreign currency transactions are recognized in the consolidated statements of income. Recorded balances that are denominated in a currency other than the functional currency are remeasured to the functional currency using the exchange rate at the balance sheet date and gains or losses are recorded in the statements of income.

Revenue Recognition and Deferred Revenue

During 2015, the Company provided environmental, energy, lodging and industrial services through six segments: Technical Services, Industrial and Field Services, Kleen Performance Products, SK Environmental Services, Lodging Services, and Oil and Gas Field Services. The Company recognizes revenue when persuasive evidence of an arrangement exists, delivery has occurred or services have been rendered, the price is fixed or determinable, and collection is reasonably assured. Revenue is recognized net of estimated allowances. Revenue is generated by short-term projects, most of which are governed by master service agreements that are long-term in nature. The master service agreements are typically entered into with the Company's larger customers and outline the pricing and legal frameworks for such arrangements.

Due to the nature of the Company's business and the invoices that result from the services provided, customers may withhold payments and attempt to renegotiate amounts invoiced. Accordingly, management establishes a revenue allowance to cover the estimated amounts of revenue that may need to be credited to customers' accounts in future periods. The Company records a provision for revenue allowances based on specific review of particular customers, historical trends and other relevant information.

Technical Services revenue is generated from fees charged for hazardous material management and disposal services including onsite environmental management services, collection and transportation, packaging, recycling, treatment and disposal of hazardous and non-hazardous waste. Services are provided based on purchase orders or agreements with the customer and include prices based upon units of volume of waste, and transportation and other fees. Collection and transportation, and packaging revenues are recognized when the transported waste is received at the disposal facility. Revenues for treatment and disposal of hazardous waste are recognized upon completion of wastewater treatment, final disposition in a landfill or incineration of the waste, all at Company-owned sites, or when the waste is shipped to a third party for processing and disposal. Revenues from recycled oil and recycled catalyst are recognized upon shipment to the customer. Revenue for all other Technical Services is recognized when services are rendered. The Company, at the request of a customer, periodically enters into bundled arrangements for the collection and transportation and disposal of waste. The Company accounts for such arrangements as multiple-element arrangements with separate units of accounting. The Company measures and allocates the consideration from the arrangement to the separate units, based on evidence of the estimated selling price for each deliverable. Revenues from waste that is not yet completely processed and disposed and the related costs are deferred. The revenue is recognized and the deferred costs are expensed when the related services are completed.

Industrial Services provides industrial and specialty services, such as high-pressure and chemical cleaning, catalyst handling, decoking and pigging to refineries, chemical plants, oil sands facilities, pulp and paper mills, and other industrial facilities. These services are provided based on purchase orders or agreements with the customer and include prices based upon daily, hourly or job rates for equipment, materials and personnel. Revenues are recognized over the term of the agreements or as services are performed. Field Services provides cleanup services on customer sites or other locations on a scheduled or

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

emergency response basis. The Company's services are provided based on purchase orders or agreements with the customer and include prices based upon daily, hourly or job rates for equipment, materials and personnel. Revenues are recorded as services are performed. Revenue is recognized on contracts with retainage when services have been rendered and collectability is reasonably assured.

Kleen Performance Products revenue is generated from re-refining used oil to produce high quality base and blended lubricating oils, and recycling used oil collected in excess of the Company's re-refining capacity into recycled fuel oil. The high quality base and blended lubricating oils are sold to third-party distributors, retailers, government agencies, fleets, railroads and industrial customers. The recycled fuel oil is sold to asphalt plants, industrial plants, blenders, pulp and paper companies, vacuum gas oil producers and marine diesel oil producers. Revenue is recognized upon the transfer of title.

SK Environmental Services revenue is generated from providing parts cleaning services, containerized waste services, oil collection services and other complementary products and services. Revenue is recognized when products are delivered and services are performed. Parts cleaning services generally consist of placing a specially designed parts washer at a customer's premises and then, on a recurring basis, delivering clean solvent or aqueous-based washing fluid, cleaning and servicing the parts washer and removing the used solvent or aqueous fluid. The Company also services customer-owned parts washers. Revenue from parts cleaning services is recognized over the service interval. Service intervals represent the actual amount of time between service visits to a particular parts cleaning customer. Average service intervals vary from seven to 14 weeks depending on several factors, such as customer accommodation, types of machines serviced and frequency of use. Containerized waste services consist of profiling, collecting, transporting and recycling or disposing of a wide variety of hazardous and non-hazardous wastes. Collection and transportation, and packaging revenues are recognized when the transported waste is received at the disposal facility. Revenues for treatment and disposal of the waste is recognized upon disposal, or when the waste is shipped to a third party for processing and disposal. Other complementary products and services include vacuum services, sale of allied supply products and other environmental services.

Lodging Services provides accommodation services, along with catering and hospitality primarily in remote areas of Western Canada. In addition, within Lodging Services is a manufacturing unit that provides construction of modular buildings including modular camp accommodations and wastewater solutions. Revenue for lodging and related services is recognized in the period each room is used by the customer based on the related lodging agreements. Revenue for manufacturing services is recognized based on contracted terms resulting in either a percentage of completion methodology or upon transfer of ownership of completed units.

Oil and Gas Field Services provides fluid handling, fluid hauling, production servicing, surface rentals, seismic services, and directional boring services to the energy sector serving oil and gas exploration and production and power generation. These services are provided based on purchase orders or agreements with the customer and include prices based upon daily, hourly or job rates for equipment, materials and personnel. Revenues for such services are recognized over the term of the agreements or as services are performed. Oil and Gas Field Services also provides equipment rentals to support drill sites. Revenue from rentals is recognized ratably over the rental period.

For all periods presented, amounts billed to customers related to shipping and handling are classified as revenue and the Company's shipping and handling costs are included in costs of revenues. In the course of the Company's operations, it collects sales tax from its customers and recognizes a current liability which is then relieved when the taxes are remitted to the appropriate governmental authorities. The Company excludes the sales tax collected from its revenues.

Advertising Expense

Advertising costs are expensed as incurred. Advertising expense was approximately $15.0 million in 2015, $11.3 million in 2014 and $10.8 million in 2013.

Stock-Based Compensation

Stock-based compensation cost is measured at the grant date based on the fair value of the award and is recognized as expense over the requisite service period, which generally represents the vesting period, and includes an estimate of awards that will be forfeited. In addition, the Company issues awards with performance targets which are recognized as expense over the requisite service period when management believes it is probable those targets will be achieved. The fair value of the

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

Company's grants of restricted stock are based on the quoted market price for the Company's common stock on the respective dates of grant. The fair value of stock options is calculated using the Black-Scholes option-pricing model. Compensation expense is based on the number of awards expected to vest. Forfeitures estimated when recognizing compensation expense are adjusted when actual forfeitures differ from the estimate.

Income Taxes

There are two major components of income tax expense, current and deferred. Current income tax expense approximates cash to be paid or refunded for taxes for the applicable period. Deferred tax expense or benefit is the result of changes between deferred tax assets and liabilities. Deferred tax assets and liabilities are determined based upon the temporary differences between the financial statement basis and tax basis of assets and liabilities as well as from net operating loss and tax credit carryforwards as measured by the enacted tax rates, which will be in effect when these differences reverse. The Company evaluates the recoverability of future tax deductions and credits and a valuation allowance is established by tax jurisdiction when, based on an evaluation of objective verifiable evidence, it is more likely than not that some portion or all of deferred tax assets will not be realized.

The Company recognizes and measures a tax benefit from uncertain tax positions when it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The Company recognizes a liability for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. The Company adjusts these liabilities when its judgment changes as a result of the evaluation of new information not previously available. Due to the complexity of some of these uncertainties, the ultimate resolution may result in a payment that is materially different from the current estimate or future recognition of an unrecognized benefit. These differences will be reflected as increases or decreases to income tax expense in the period in which they are determined.

The Company recognizes interest and penalties related to unrecognized tax benefits within the income tax expense line in the consolidated statements of income. Accrued interest and penalties are included within deferred taxes, unrecognized tax benefits and other long-term liabilities line in the consolidated balance sheet.

Earnings (Loss) per Share ("EPS")

Basic EPS is calculated by dividing income available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted EPS gives effect to all potentially dilutive common shares that were outstanding during the period.

Business Combinations

For all business combinations, the Company records 100% of all assets and liabilities of the acquired business, including goodwill, at their estimated fair values. Acquisition-related costs are expensed in the period in which the costs are incurred and the services are received.

Recent Accounting Pronouncements

Standards implemented

In April 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“ASU”) 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360)*. The amendments in ASU 2014-08 provide guidance for the recognition and disclosure of discontinued operations. The adoption of ASU 2014-08 did not have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, *Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized liability in the balance sheet be presented as a direct deduction to that liability rather than as an asset. Final guidance on this standard, issued as ASU 2015-15 in August 2015, includes an SEC staff announcement that the SEC staff will not object to an entity presenting the cost of securing a revolving line of credit as an asset, regardless of whether a balance is outstanding. The Company elected to early adopt this new standard beginning December 31, 2015 and retrospectively reclassified $14.9 million of debt issuance costs associated with the Company's long-term obligations as of December 31, 2014 from other assets to long-term obligations. This reclassification only affected presentation and therefore did not have an impact on the Company’s results

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) SIGNIFICANT ACCOUNTING POLICIES (Continued)

of operations. Costs associated with securing the Company's revolving credit facility remained presented as Deferred financing costs within the Other assets section of the consolidated balance sheets for all periods presented.

In November 2015, FASB issued ASU 2015-17, *Income Taxes (Topic 740)*. The amendment provides guidance to simplify the presentation of deferred taxes by requiring that deferred liabilities and assets be classified as noncurrent in a classified balance sheet. The Company elected to early adopt this new standard beginning December 31, 2015 and prospectively applied ASU 2015-17, therefore deferred tax balances presented for periods prior to December 31, 2015 have not been recast in connection with the implementation of this standard. The adoption of this standard only affects the classification of deferred tax amounts and has no impact on the Company's results of operations.

Standards to be implemented

In May 2014, FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. ASU 2014-09 outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. In August 2015, FASB issued ASU 2015-14 which deferred the effective date of ASU 2014-09 for all entities by one year. This new guidance is currently effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2017.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810)*. The amendment provides guidance regarding amendments to the consolidation analysis. The amendments in this update are currently effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2015.

In January 2016, FASB issued ASU 2016-01, *Financial Instruments - Overall (Subtopic 825-10)*. The amendment provides guidance to enhance the reporting model for financial instruments to provide users of financial statements with more decision-useful information. The amendment in this update is effective for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019.

The Company is currently evaluating the impact that the above standards to be implemented will have on the Company's consolidated financial statements.

In July 2015, FASB issued ASU 2015-11, *Inventory (Topic 330)*. The amendment provides guidance regarding the measurement of inventory. Entities should measure inventory within the scope of this update at the lower of cost and net realizable value. The amendments in this update are currently effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2016. Adoption is not expected to have a material impact on the Company's consolidated financial statements.

In September 2015, FASB issued ASU 2015-16, *Business Combinations (Topic 805)*. The amendment provides guidance to simplify the accounting for adjustments made to provisional amounts recognized in a business combination. This amendment eliminates the requirement to retrospectively account for those adjustments. The amendment in this update is currently effective for annual reporting periods (including interim reporting periods within those periods) beginning after December 15, 2015. Adoption is not expected to have a material impact on the Company's consolidated financial statements.

(3) BUSINESS COMBINATIONS

2015 Acquisitions

Thermo Fluids Inc.

On April 11, 2015, the Company completed the acquisition of Heckmann Environmental Services, Inc. ("HES") and Thermo Fluids Inc. ("TFI"), a wholly-owned subsidiary of HES. The acquisition was accomplished through a purchase by Safety-Kleen, Inc., a wholly-owned subsidiary of the Company, of all of the issued and outstanding shares of HES from Nuverra Environmental Solutions, Inc. HES is a holding company that does not conduct any operations. TFI provides environmental services, including used oil recycling, used oil filter recycling, antifreeze products, parts washers and solvent recycling, and industrial waste management services, including vacuum services, remediation, lab pack and hazardous waste

(3) BUSINESS COMBINATIONS (Continued)

management. The Company acquired TFI for an estimated preliminary purchase price of $78.6 million inclusive of current estimates of and subject to certain closing and post-closing adjustments relating to working capital and other assumed liabilities. The acquisition was financed with cash on hand and expands the Company's environmental services customer base while also complimenting the SK Environmental Services network and presence in the western United States. The amount of
revenue from TFI included in the Company's results of operations for the year ended December 31, 2015 was $33.8 million. During the year ended December 31, 2015, the Company incurred acquisition-related costs of approximately $0.6 million in connection with the transaction which are primarily included in selling, general and administrative expenses in the consolidated statements of income. Results of TFI since acquisition have been included within the SK Environmental Services segment.

The allocation of the purchase price was based on preliminary estimates of the fair value of assets acquired and liabilities assumed as of April 11, 2015, as the Company is continuing to obtain information to complete its valuation of these accounts and the associated tax accounting. The components and preliminary allocation of the purchase price consist of the following amounts (in thousands):

	At acquisition date April 11, 2015	Measurement Period Adjustments	At acquisition date as reported at December 31, 2015
Accounts Receivable	$ 7,109	$ 476	$ 7,585
Inventories and supplies	1,791	—	1,791
Prepaid expenses and other current assets	1,749	(1,084)	665
Property, plant and equipment	30,468	(1,606)	28,862
Permits and other intangibles	20,000	(1,900)	18,100
Current liabilities	(5,859)	14	(5,845)
Closure and post-closure liabilities	(1,676)	—	(1,676)
Deferred taxes, unrecognized tax benefits and other long-term liabilities	(13,081)	3,051	(10,030)
Total identifiable net assets	40,501	(1,049)	39,452
Goodwill	36,591	2,543	39,134
Total	$ 77,092	$ 1,494	$ 78,586

Pro forma revenue and earnings amounts on a combined basis as if TFI had been acquired on January 1, 2015 are immaterial to the consolidated financial statements of the Company since that date.

Other 2015 Acquisitions

In December 2015, the Company acquired certain assets and assumed certain defined liabilities of a privately owned company for approximately $14.7 million in cash. That company specializes in the collection and recycling of used oil filters and was a service provider to the SK Environmental Services segment prior to the acquisition. The acquired company has been integrated into the SK Environmental Services segment. In connection with this acquisition a preliminary goodwill amount of $7.4 million was recognized.

2014 Acquisitions

In 2014, the Company acquired the assets of two privately owned companies for approximately $16.1 million in cash, net of cash acquired. The acquired companies have been integrated into the Technical Services and Lodging Services segments.

2013 Acquisitions

Evergreen

On September 13, 2013, the Company acquired all of the outstanding shares of Evergreen Oil, Inc. ("Evergreen") for a final purchase price of $56.3 million in cash, net of cash acquired. Evergreen, headquartered in Irvine, California, specializes in the recovery and re-refining of used oil. Evergreen owns and operates one of the only oil re-refining operations in the Western United States and also offers other ancillary environmental services, including parts cleaning and containerized waste services, vacuum services and hazardous waste management services. The acquisition of Evergreen enables the Company to further penetrate the small quantity waste generator market and further expand its oil re-refining, oil recycling and waste treatment capabilities. Financial information and results of Evergreen have been recorded in the Company's consolidated financial statements since acquisition and are primarily included in the Kleen Performance Products segment.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) BUSINESS COMBINATIONS (Continued)

Management determined the purchase price allocations based on estimates of the fair values of all tangible and intangible assets acquired and liabilities assumed. The Company believes that such information provides a reasonable basis for estimating the fair values of assets acquired and liabilities assumed. The Company finalized the purchase accounting for the acquisition of Evergreen. The impact of the purchase price measurement period adjustments and related tax impacts recorded in the current period was not material to the consolidated financial statements and accordingly the effects have not been retrospectively applied.

The following table summarizes the recognized amounts of assets acquired and liabilities assumed at September 13, 2013 (in thousands):

	Preliminary Allocations	Measurement Period Adjustments	Final Allocations
Inventories and supplies	$ 1,089	$ —	$ 1,089
Prepaid expense and other current assets	1,291	(273)	1,018
Property, plant and equipment	40,563	—	40,563
Permits and other intangibles	17,100	—	17,100
Deferred tax assets, less current portion	2,368	(2,368)	—
Other assets	3,607	(239)	3,368
Current liabilities	(6,198)	(552)	(6,750)
Closure and post-closure liabilities	(659)	—	(659)
Remedial liabilities, less current portion	(2,103)	463	(1,640)
Other long-term liabilities	(1,139)	(920)	(2,059)
Total identifiable net assets	55,919	(3,889)	52,030
Goodwill	—	4,288	4,288
Total	$ 55,919	$ 399	$ 56,318

(4) INVENTORIES AND SUPPLIES

Inventories and supplies consisted of the following (in thousands):

	December 31, 2015	December 31, 2014
Oil and oil products	$ 33,603	$ 62,111
Supplies and drums	78,132	68,547
Solvent and solutions	8,868	9,355
Modular camp accommodations	15,126	15,776
Other	13,792	12,874
Total inventories and supplies	$ 149,521	$ 168,663

As of December 31, 2015 and 2014, other inventories consisted primarily of cleaning fluids, such as absorbents and wipers, and automotive fluids, such as windshield washer fluid and antifreeze.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following (in thousands):

	December 31, 2015	December 31, 2014
Land	$ 100,582	$ 98,507
Asset retirement costs (non-landfill)	12,434	10,871
Landfill assets	136,624	110,984
Buildings and improvements	344,209	338,242
Camp equipment	149,361	180,575
Vehicles	500,619	471,615
Equipment	1,328,915	1,302,424
Furniture and fixtures	5,337	5,517
Construction in progress	113,657	45,605
	2,691,738	2,564,340
Less - accumulated depreciation and amortization	1,159,271	1,005,506
Total property, plant and equipment, net	$ 1,532,467	$ 1,558,834

Interest in the amount of $2.0 million, $0.5 million and $0.9 million was capitalized to fixed assets during the years ended December 31, 2015, 2014 and 2013, respectively. Depreciation expense, inclusive of landfill amortization was $234.0 million, $239.4 million and $229.4 million for the years ended December 31, 2015, 2014 and 2013, respectively.

(6) GOODWILL AND OTHER INTANGIBLE ASSETS

The changes in goodwill for the years ended December 31, 2015 and 2014 were as follows (in thousands):

	Technical Services	Industrial and Field Services	Kleen Performance Products	SK Environmental Services	Lodging Services	Oil and Gas Field Services	Totals
Balance at January 1, 2014	$ 45,599	$ 109,873	$ 171,161	$ 172,309	$ 35,512	$ 36,506	$ 570,960
Acquired from acquisitions	5,018	—	—	—	2,383	—	7,401
Measurement period adjustments	—	—	4,288	—	—	—	4,288
Goodwill impairment charge	—	—	(123,414)	—	—	—	(123,414)
Foreign currency translation and other	(525)	(659)	(1,152)	1,564	(3,032)	(2,762)	(6,566)
Balance at December 31, 2014	$ 50,092	$ 109,214	$ 50,883	$ 173,873	$ 34,863	$ 33,744	$ 452,669
Acquired from acquisitions	—	—	—	46,539	—	—	46,539
Measurement period adjustments	—	—	—	—	3,574	—	3,574
Goodwill impairment charge	—	—	—	—	—	(31,992)	(31,992)
Foreign currency translation and other	(825)	(3,928)	(1,128)	(3,823)	(6,229)	(1,752)	(17,685)
Balance at December 31, 2015	$ 49,267	$ 105,286	$ 49,755	$ 216,589	$ 32,208	$ —	$ 453,105

The Company assesses goodwill for impairment on an annual basis as of December 31, or at an interim date when events or changes in the business environment would more likely than not reduce the fair value of a reporting unit below its carrying value.

During the second quarter of 2015, certain events and changes in circumstances arose which led management of the Company to conclude that the fair value of the Oil and Gas Field Services reporting unit may be less than its carrying value and therefore an interim impairment test was conducted relative to goodwill recorded by the Oil and Gas Field Services reporting unit. The primary events and changes in circumstances which led to this conclusion were:

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(6) GOODWILL AND OTHER INTANGIBLE ASSETS (Continued)

- The second quarter is the period of time where greater levels of communication with customers and the receipt of bids and proposals for project work take place and provide management with more clarity into levels of activity and other economic and business indicators for the latter half of the fiscal year and on into the first quarter of the following year. During the quarter ended June 30, 2015, it became apparent that oil and gas exploration and production activity would continue to be lower than historical periods and lower than previously anticipated by the Company. This was evidenced by reduced volume in bid and proposal requests from customers and communications indicating the reduction in customer budgets in these areas as well as lower than anticipated pricing for our services.

- Market and industry reports which management looks to in projecting business conditions and establishing forecast information evidenced more pessimistic views in the near term. The continued depressed price of oil without any upward momentum since December 2014, as well as declining and expected continued decline in rig count for the remainder of 2015, resulted in lower estimates of industry activity in the second half of 2015 and early 2016.

- In recognition of lower than anticipated business results and less optimistic market indicators, management significantly lowered its 2015 forecasts relative to the Oil and Gas Field Services reporting unit.

In performing Step I of this interim goodwill impairment test, the estimated fair value of the Oil and Gas Field Services reporting unit was determined using an income approach based upon discounted cash flows and was compared to the reporting unit's carrying value as of June 30, 2015. Based on the results of that valuation, the carrying amount of the reporting unit, including $32.0 million of goodwill, exceeded its estimated fair value and as a result the Company performed Step II of the goodwill impairment test to determine the amount of goodwill impairment charge to be recorded.

Step II of the goodwill impairment test required the Company to perform a theoretical purchase price allocation for the reporting unit to determine the implied fair value of goodwill and to compare the implied fair value of goodwill to the recorded amount. The estimates of the fair values of intangible assets identified in performing this theoretical purchase price allocation and resulting implied fair value of goodwill required significant judgment. Based on the results of this goodwill impairment test the implied value of goodwill was $0 and as such the Company recognized a goodwill impairment charge equal to the recorded amount of goodwill of $32.0 million as of June 30, 2015.

The factors contributing to the $32.0 million goodwill impairment charge principally related to events and changes in circumstances discussed above which had negative impacts on the Company’s prospective financial information utilized in its discounted cash flow model prepared in connection with the interim impairment test. The projected lower levels of activity and pricing in the latter half of the year which became evident during the second quarter decreased the reporting unit’s anticipated future cash flows for 2015 as compared to those estimated previously. These factors also provided evidence of a longer than expected overall recovery from current industry lows which negatively impacted the estimated levels of cash flows in future periods that were assumed in the cash flow models utilized in the interim impairment test. These factors adversely affected the estimated fair value of the reporting unit as of June 30, 2015 and ultimately led to the recognition of the goodwill impairment charge.

During the third quarter of 2014 the Company recorded a goodwill impairment charge of $123.4 million related to goodwill associated with the Kleen Performance Products segment.

In performing Step I of this goodwill impairment test, the estimated fair value of the Oil Re-refining and Recycling reporting unit was determined using an income approach based upon discounted cash flows and was compared to the reporting unit's carrying value as of September 30, 2014. Based on the results of that valuation, the carrying amount of the reporting unit, including $174.3 million of goodwill, exceeded its estimated fair value and as a result the Company performed Step II of the goodwill impairment test to determine the amount of goodwill impairment charge to be recorded.

Step II of the goodwill impairment test required the Company to perform a theoretical purchase price allocation for the reporting unit to determine the implied fair value of goodwill and to compare the implied fair value of goodwill to the recorded amount. The estimates of the fair values of intangible assets identified in performing this theoretical purchase price allocation and resulting implied fair value of goodwill required significant judgment. Based on the results of this goodwill impairment
test, the Company recognized a goodwill impairment charge for the Oil Re-refining and Recycling segment of $123.4 million as of September 30, 2014.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(6) GOODWILL AND OTHER INTANGIBLE ASSETS (Continued)

The factors contributing to this goodwill impairment charge principally related to decreases in market prices of oil products sold by the Kleen Performance Products business which took place during the third quarter of 2014. These decreasing market prices negatively impacted the profitability of the Oil Re-refining and Recycling segment and further resulted in lower assumptions for future revenues and profits of the business. These factors adversely affected the estimated fair value of the reporting unit as of September 30, 2014 and ultimately led to the recognition of the goodwill impairment charge.

The Company conducted its annual impairment test of goodwill for all of the Company's reporting units as of December 31, 2015 and determined that no adjustment to the carrying value of goodwill for any reporting unit was necessary because the fair values of the reporting units exceeded their respective carrying values. The fair value of all reporting units was determined using an income approach based upon estimates of future discounted cash flows. The resulting estimates of fair value were validated through the consideration of other factors such as the fair value of comparable companies to the reporting units and a reconciliation of the sum of all estimated fair values of the reporting units to the Company’s overall market capitalization. In all cases except for the Company's Kleen Performance Products reporting unit, the estimated fair values of the reporting units significantly exceeded their carrying values.

Significant judgments and unobservable inputs categorized as Level III in the fair value hierarchy are inherent in the impairment tests performed and include assumptions about the amount and timing of expected future cash flows, growth rates, and the determination of appropriate discount rates. The Company believes that the assumptions used in its annual and any interim date impairment tests are reasonable, but variations in any of the assumptions may result in different calculations of fair values and impairment charges.

The impacts of any adverse business and market conditions which impact the overall performance of the Company's reporting units will continue to be monitored. If the Company's reporting units do not achieve the financial performance that the Company expects, it is possible that additional goodwill impairment charges may result. There can therefore be no assurance that future events will not result in an impairment of goodwill.

At December 31, 2015, the total accumulated goodwill impairment charge was $155.4 million, of which $32.0 million was recorded during the year ended December 31, 2015 within the Oil and Gas Field Services segment and $123.4 million was recorded in the Kleen Performance Products segment during the year ended December 31, 2014.

As of December 31, 2015 and 2014, the Company's finite-lived and indefinite lived intangible assets consisted of the following (in thousands):

	December 31, 2015				December 31, 2014			
	Cost	Accumulated Amortization	Net	Weighted Average Amortization Period (in years)	Cost	Accumulated Amortization	Net	Weighted Average Amortization Period (in years)
Permits	$ 161,396	$ 61,142	$ 100,254	19.0	$ 156,692	$ 55,318	$ 101,374	19.0
Customer and supplier relationships	374,866	99,463	275,403	10.1	370,373	77,697	292,676	11.0
Other intangible assets	31,416	22,581	8,835	1.5	31,540	19,074	12,466	3.2
Total amortizable permits and other intangible assets	567,678	183,186	384,492	10.0	558,605	152,089	406,516	11.4
Trademarks and trade names	122,326	—	122,326	Indefinite	123,564	—	123,564	Indefinite
Total permits and other intangible assets	$ 690,004	$ 183,186	$ 506,818		$ 682,169	$ 152,089	$ 530,080	

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(6) GOODWILL AND OTHER INTANGIBLE ASSETS (Continued)

As of December 31, 2015, the Oil and Gas Field Services segment group had property, plant and equipment, net of $156.3 million, other intangible assets of $14.9 million consisting of customer and supplier relationships of $8.2 million and other intangible assets of $6.7 million. Based on analyses performed during 2015 which were conducted based upon the same circumstances which triggered the goodwill impairment charge recorded, sufficient undiscounted cash flows are expected to be generated over these assets' remaining lives to recover the carrying values and thus no impairment exists. If expectations of future cash flows were to decrease in the future as a result of worse than expected or prolonged periods of depressed activity in the Oil and Gas Field Services marketplace, future impairments may exist.

Amortization expense of permits and other intangible assets for the years ended December 31, 2015, 2014 and 2013 were $40.2 million, $36.7 million and $35.1 million, respectively.

The expected amortization of the net carrying amount of finite-lived intangible assets at December 31, 2015 is as follows(in thousands):

Years Ending December 31,	Expected Amortization
2016	$ 37,902
2017	33,081
2018	30,450
2019	27,926
2020	25,539
Thereafter	229,594
	$ 384,492

(7) ACCRUED EXPENSES

Accrued expenses consisted of the following at December 31 (in thousands):

	December 31, 2015	December 31, 2014
Insurance	$ 55,899	$ 58,931
Interest	20,500	20,527
Accrued compensation and benefits	35,646	59,006
Income, real estate, sales and other taxes	37,095	38,297
Other	44,520	42,788
	$ 193,660	$ 219,549

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(8) CLOSURE AND POST-CLOSURE LIABILITIES

The changes to closure and post-closure liabilities (also referred to as "asset retirement obligations") from January 1, 2014 through December 31, 2015 were as follows (in thousands):

	Landfill Retirement Liability	Non-Landfill Retirement Liability	Total
Balance at January 1, 2014	$ 27,604	$ 19,481	$ 47,085
New asset retirement obligations	3,595	—	3,595
Accretion	2,583	1,875	4,458
Changes in estimates recorded to statement of income	(722)	73	(649)
Changes in estimates recorded to balance sheet	(1,304)	—	(1,304)
Expenditures	(1,580)	(546)	(2,126)
Currency translation and other	(244)	(114)	(358)
Balance at December 31, 2014	29,932	20,769	50,701
Liabilities assumed in TFI acquisition	—	1,676	1,676
New asset retirement obligations	3,151	—	3,151
Accretion	2,516	2,122	4,638
Changes in estimates recorded to statement of income (loss)	(162)	205	43
Changes in estimates recorded to balance sheet	2,942	—	2,942
Expenditures	(5,946)	(177)	(6,123)
Currency translation and other	(410)	(369)	(779)
Balance at December 31, 2015	$ 32,023	$ 24,226	$ 56,249

All of the landfill facilities included in the above table were active as of December 31, 2015 and 2014. There were no significant charges (benefits) in 2015 and 2014 resulting from changes in estimates for closure and post-closure liabilities.

New asset retirement obligations incurred during 2015 and 2014 were discounted at the credit-adjusted risk-free rate of 5.99% and 6.54%, respectively.

Anticipated payments (based on current estimated costs and anticipated timing of necessary regulatory approvals to commence work on closure and post-closure activities) for each of the next five years and thereafter are as follows (in thousands):

Year ending December 31,	
2016	$ 8,160
2017	9,061
2018	9,001
2019	7,621
2020	3,442
Thereafter	262,365
Undiscounted closure and post-closure liabilities	299,650
Less: Discount at credit-adjusted risk-free rate	(156,145)
Less: Undiscounted estimated closure and post-closure liabilities relating to airspace not yet consumed	(87,256)
Present value of closure and post-closure liabilities	$ 56,249

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(9) REMEDIAL LIABILITIES

The changes to remedial liabilities from January 1, 2014 through December 31, 2015 were as follows (in thousands):

	Remedial Liabilities for Landfill Sites	Remedial Liabilities for Inactive Sites	Remedial Liabilities (Including Superfund) for Non-Landfill Operations	Total
Balance at January 1, 2014	$ 5,624	$ 74,262	$ 92,612	$ 172,498
Adjustments during the measurement period related to Evergreen	—	—	(536)	(536)
Accretion	266	2,975	2,913	6,154
Changes in estimates recorded to statement of income (loss)	(113)	(2,645)	40	(2,718)
Expenditures	(109)	(5,940)	(12,070)	(18,119)
Currency translation and other	(248)	(124)	(1,786)	(2,158)
Balance at December 31, 2014	5,420	68,528	81,173	155,121
Accretion	218	2,924	2,622	5,764
Changes in estimates recorded to statement of income (loss)	(2,841)	(2,927)	(5,620)	(11,388)
Expenditures	(137)	(4,779)	(9,091)	(14,007)
Currency translation and other	(333)	(133)	(3,032)	(3,498)
Balance at December 31, 2015	$ 2,327	$ 63,613	$ 66,052	$ 131,992

In 2015, the net reduction in the Company's remedial liabilities from changes in estimates recorded to the statement of income (loss) was $11.4 million and primarily related to reductions in the estimates for remedial activities at four locations. Events which occurred during 2015 and resulted in the changes in estimates were attributable to favorable outcomes from negotiations amongst potentially responsible parties which the Company participates in of $3.8 million, the results of work performed by external third party consultants who were engaged to aid the Company in estimating future remedial activity costs at certain sites of $4.7 million and the result of receiving Provincial approval for a planned expansion of one of the Company's landfills in Canada which as a result will remediate the Company's previously recognized obligations of $2.5 million.

In 2014, the reduction in changes in estimates recorded to the statement of income (loss) was primarily related to estimated cost adjustments for remediation across various sites.

Anticipated payments at December 31, 2015 (based on current estimated costs and anticipated timing of necessary regulatory approvals to commence work on remedial activities) for each of the next five years and thereafter were as follows (in thousands):

Year ending December 31,	
2016	$ 13,525
2017	14,004
2018	15,907
2019	10,626
2020	9,963
Thereafter	94,116
Undiscounted remedial liabilities	158,141
Less: Discount	(26,149)
Total remedial liabilities	$ 131,992

Based on currently available facts and legal interpretations, existing technology, and presently enacted laws and regulations, the Company estimates that its aggregate liabilities as of December 31, 2015 for future remediation relating to all of its owned or leased facilities and the Superfund sites for which the Company has current or potential future liability is approximately $132.0 million. The Company also estimates that it is reasonably possible that the amount of such total liabilities could be as much as $23.6 million more. Future changes in either available technology or applicable laws or regulations could

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(9) REMEDIAL LIABILITIES (Continued)

affect such estimates of remedial liabilities. Since the Company's satisfaction of the liabilities will occur over many years, the Company cannot now reasonably predict the nature or extent of future changes in either available technology or applicable laws or regulations and the impact that those changes, if any, might have on the current estimates of remedial liabilities.

The following tables show, respectively, (i) the amounts of such estimated liabilities associated with the types of facilities and sites involved and (ii) the amounts of such estimated liabilities associated with each facility or site which represents at least 5% of the total and with all other facilities and sites as a group and as of December 31, 2015.

Estimates Based on Type of Facility or Site (in thousands):

Type of Facility or Site	Remedial Liability	% of Total	Reasonably Possible Additional Liabilities(1)
Facilities now used in active conduct of the Company's business (47 facilities)	$ 59,022	44.7%	$ 12,157
Inactive facilities not now used in active conduct of the Company's business but most of which were acquired because the assumption of remedial liabilities for such facilities was part of the purchase price for the CSD assets (40 facilities)	63,613	48.2	10,543
Superfund sites owned by third parties (17 sites)	9,357	7.1	936
Total	$ 131,992	100.0%	$ 23,636

(1) Amounts represent the high end of the range of management's best estimate of the reasonably possible additional liabilities.

Estimates Based on Amount of Potential Liability (in thousands):

Location	Type of Facility or Site	Remedial Liability	% of Total	Reasonably Possible Additional Liabilities(1)
Baton Rouge, LA(2)	Closed incinerator and landfill	$ 23,572	17.9%	$ 3,931
Bridgeport, NJ	Closed incinerator	18,623	14.1	2,568
Mercier, Quebec(2)	Idled incinerator and legal proceedings	9,012	6.8	947
Linden, NJ	Operating solvent recycling center	8,069	6.1	867
Various(2)	All other incinerators, landfills, wastewater treatment facilities and service centers (83 facilities)	63,359	48.0	14,387
Various(2)	Superfund sites (each representing less than 5% of total liabilities) owned by third parties (17 sites)	9,357	7.1	936
Total		$ 131,992	100.0%	$ 23,636

(1) Amounts represent the high end of the range of management's best estimate of the reasonably possible additional liabilities.

(2) $18.9 million of the $132.0 million remedial liabilities and $1.9 million of the $23.6 million reasonably possible additional liabilities include estimates of remediation liabilities related to the legal and administrative proceedings discussed in Note 16, "Commitments and Contingencies," as well as other such estimated remedial liabilities.

Revisions to remediation reserve requirements may result in upward or downward adjustments to income from operations in any given period. The Company believes that its extensive experience in the environmental services business, as well as its involvement with a large number of sites, provides a reasonable basis for estimating its aggregate liability. It is possible, however, that technological, regulatory or enforcement developments, the results of environmental studies, or other factors could necessitate the recording of additional liabilities or the revision of currently recorded liabilities that could be material. The impact of such future events cannot be estimated at the current time.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) FINANCING ARRANGEMENTS

The following table is a summary of the Company's financing arrangements (in thousands):

	December 31, 2015	December 31, 2014
Senior unsecured notes, at 5.25%, due August 1, 2020	$ 800,000	$ 800,000
Senior unsecured notes, at 5.125%, due June 1, 2021	595,000	595,000
Long-term obligations, at par	$ 1,395,000	$ 1,395,000
Unamortized debt issuance costs	$ (12,457)	$ (14,855)
Long-term obligations, at carrying value	$ 1,382,543	$ 1,380,145

Senior Unsecured Notes, at 5.25%, due August 1, 2020. On July 30, 2012, the Company issued through a private placement $800.0 million aggregate principal amount of 5.25% senior unsecured notes due August 1, 2020 ("2020 Notes") with semi-annually fixed interest payments on February 1 and August 1 of each year, which commenced on February 1, 2013. On November 16, 2012, the Company completed an exchange offer for the unregistered 2020 Notes originally issued in the private placement for an equivalent amount of 2020 Notes the Company had registered under the Securities Act of 1933, as amended (the "Securities Act"), pursuant to a registration statement which became effective in October 2012. At December 31, 2015 and December 31, 2014, the fair value of the Company's 2020 Notes was $812.0 million and $804.0 million, respectively, based on quoted market prices for the instrument. The fair value of the 2020 Notes is considered a Level 2 measure according to the fair value hierarchy.

The Company may redeem some or all of the 2020 Notes at any time on or after August 1, 2016 upon proper notice, at the following redemption prices plus unpaid interest:

Year	Percentage
2016	102.625%
2017	101.313%
2018 and thereafter	100.000%

At any time, or from time to time, prior to August 1, 2016, the Company may also redeem some or all of the 2020 Notes at a redemption price of 100% of the principal amount plus a make-whole premium and any accrued and unpaid interest.

The 2020 Notes and the related indenture contain various customary non-financial covenants and are guaranteed by substantially all of the Company's current and future domestic restricted subsidiaries. The 2020 Notes are the Company's and the guarantors' senior unsecured obligations ranking equally with the Company's and the guarantors' existing and future senior unsecured obligations and senior to any future indebtedness that is expressly subordinated to the 2020 Notes and the guarantees. The 2020 Notes and the guarantees rank effectively junior in right of payment to the Company's and the guarantors' secured indebtedness (including loans and reimbursement obligations in respect of outstanding letters of credit) under the Company's revolving credit facility and capital lease obligations to the extent of the value of the assets securing such secured indebtedness. The 2020 Notes are not guaranteed by the Company's Canadian or other foreign subsidiaries, and the 2020 Notes are structurally subordinated to all indebtedness and other liabilities, including trade payables, of the Company's subsidiaries that are not guarantors of the 2020 Notes.

Senior Unsecured Notes, at 5.125%, due June 1, 2021. On December 7, 2012, the Company issued through a private placement $600.0 million aggregate principal amount of 5.125% senior unsecured notes due 2021 ("2021 Notes"). The Company used the net proceeds from such private placement to fund a portion of the purchase price to acquire Safety-Kleen. On May 21, 2013, the Company completed an exchange offer for the unregistered 2021 Notes originally issued in the private placement for an equivalent amount of 2021 Notes the Company had registered under the Securities Act pursuant to a registration statement which became effective in April 2013. The Company repurchased $5.0 million principal amount of the 2021 Notes during 2014. At December 31, 2015 and 2014, the fair value of the Company's 2021 Notes was $599.5 million and $595.0 million, respectively, based on quoted market prices or other available market data. The fair value of the 2021 Notes is considered a Level 2 measure according to the fair value hierarchy.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) FINANCING ARRANGEMENTS (Continued)

The principal terms of the 2021 Notes are as follows:

The 2021 Notes will mature on June 1, 2021. The notes bear interest at a rate of 5.125% per annum. Interest is payable semi-annually on June 1 and December 1 of each year. The Company may redeem some or all of the 2021 Notes at any time on or after December 1, 2016 upon proper notice, at the following redemption prices plus unpaid interest: .

Year	Percentage
2016	102.563%
2017	101.281%
2018 and thereafter	100.000%

At any time, or from time to time, prior to December 1, 2016, the Company may redeem some or all of the 2021 Notes at a price equal to 100% of the principal amount plus a make-whole premium and accrued and unpaid interest.

The 2021 Notes and the related indenture contain various customary non-financial covenants and are guaranteed by substantially all the Company's current and future domestic restricted subsidiaries. The 2021 Notes are the Company's and the guarantors' senior unsecured obligations ranking equally with the Company's and the guarantors' existing and future senior unsecured obligations and senior to any future indebtedness that is expressly subordinated to the 2021 Notes and the guarantees. The 2021 Notes are effectively subordinated to all of the Company's and the Company's subsidiaries secured indebtedness under the Company's revolving credit facility and capital lease obligations to the extent of the value of the assets securing such secured indebtedness. The 2021 Notes are not guaranteed by the Company's existing and future Canadian or other foreign subsidiaries, and the 2021 Notes are structurally subordinated to all indebtedness and other liabilities, including trade payables, of the Company's subsidiaries that are not guarantors of the 2021 Notes.

Revolving Credit Facility. On January 17, 2013, the Company entered into an amendment and restatement of the previously existing revolving credit facility with Bank of America, N.A. (“BofA”), as agent for the lenders under the facility. The principal terms of the facility are:

(i) the maximum amount of borrowings and letters of credit which the Company may obtain under the facility is $400.0 million (with a $325.0 million sub-limit for letters of credit);

(ii) of such $400.0 million maximum amount, $300.0 million (with a $250.0 million sub-limit for letters of credit) is available for Clean Harbors, Inc. ("Parent") and its domestic subsidiaries and $100.0 million (with a $75.0 million sub-limit for letters of credit) is available for Parent's Canadian subsidiaries;

(iii) the interest rate on borrowings under the facility, in the case of LIBOR loans, is LIBOR plus an applicable margin ranging (depending primarily on the Company's fixed charge coverage ratio for the most recently completed four fiscal quarters) from 1.50% to 2.00% per annum, and, in the case of base rate loans, BofA's base rate plus an applicable margin ranging from 0.50% to 1.00% per annum, and with such reduced applicable margin for LIBOR loans also to be the annual fee for outstanding letters of credit; and

(iv) the term of the facility will expire on January 17, 2018.

The revolving credit facility is guaranteed by all of Parent’s domestic subsidiaries and secured by substantially all of Parent’s and its domestic subsidiaries’ assets. Available credit for Parent and its domestic subsidiaries is limited to 85% of their eligible accounts receivable and 100% of their cash deposited in a controlled account with the agent. Available credit for Parent’s Canadian subsidiaries is limited to 85% of their eligible accounts receivable and 100% of their cash deposited in a controlled account with the agent’s Canadian affiliate. The obligations of the Canadian subsidiaries under the revolving credit facility are guaranteed by all of Parent’s Canadian subsidiaries and secured by substantially all of the assets of the Canadian subsidiaries, but the Canadian subsidiaries do not guarantee and are not otherwise responsible for the obligations of Parent or its domestic subsidiaries.

The Company utilizes letters of credit primarily as security for financial assurance which it has been required to provide to regulatory bodies for its hazardous waste facilities and which would be called only in the event that the Company fails to satisfy closure, post-closure and other obligations under the permits issued by those regulatory bodies for such licensed facilities. At December 31, 2015 and 2014, the revolving credit facility had no outstanding loan balances, $178.5 million and

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(10) FINANCING ARRANGEMENTS (Continued)

$238.4 million, respectively, available to borrow and $144.6 million and $134.5 million, respectively, of letters of credit outstanding.

(11) INCOME TAXES

The domestic and foreign components of income before provision for income taxes were as follows (in thousands):

	For the Year Ended December 31,		
	2015	2014	2013
Domestic	$ 164,105	$ 44,737	$ 85,775
Foreign	(54,459)	(6,215)	58,110
Total	$ 109,646	$ 38,522	$ 143,885

The provision for income taxes consisted of the following (in thousands):

	For the Year Ended December 31,		
	2015	2014	2013
Current:			
Federal	$ 46,775	$ 17,184	$ 5,264
State	11,120	6,918	5,006
Foreign	5,719	10,428	6,930
	63,614	34,530	17,200
Deferred			
Federal	12,254	33,858	20,574
State	2,766	1,840	2,074
Foreign	(13,090)	(3,378)	8,471
	1,930	32,320	31,119
Provision for income taxes	$ 65,544	$ 66,850	$ 48,319

The Company's effective tax rate for fiscal years 2015, 2014 and 2013 was 59.8%, 173.5% and 33.6%, respectively. The effective income tax rate varied from the amount computed using the statutory federal income tax rate as follows (in thousands):

	For the Year Ended December 31,		
	2015	2014	2013
Tax expense at US statutory rate	$ 38,376	$ 13,483	$ 50,360
State income taxes, net of federal benefit	8,449	7,429	4,052
Foreign rate differential	3,951	(2,916)	(10,478)
Non-deductible transaction costs	—	—	657
Uncertain tax position releases	—	—	(4,010)
Uncertain tax position interest and penalties	32	2,217	457
Goodwill impairment	10,974	44,273	—
Other	3,762	2,364	7,281
Provision for income taxes	$ 65,544	$ 66,850	$ 48,319

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(11) INCOME TAXES (Continued)

The components of the total net deferred tax assets and liabilities at December 31, 2015 and 2014 were as follows (in thousands):

	2015	2014
Deferred tax assets:		
Workers compensation and other claims related accruals	$ 15,316	$ 15,904
Provision for doubtful accounts	12,654	8,921
Closure, post-closure and remedial liabilities	37,407	43,640
Accrued expenses	12,455	13,451
Accrued compensation	5,425	12,094
Net operating loss carryforwards(1)	41,191	46,740
Tax credit carryforwards(2)	25,040	29,347
Uncertain tax positions accrued interest and federal benefit	1,219	1,953
Stock-based compensation	615	489
Other	7,421	3,622
Total deferred tax assets	158,743	176,161
Deferred tax liabilities:		
Property, plant and equipment	(221,969)	(232,106)
Permits and other intangible assets	(159,698)	(155,326)
Total deferred tax liabilities	(381,667)	(387,432)
Total net deferred tax liability before valuation allowance	(222,924)	(211,271)
Less valuation allowance	(30,916)	(29,061)
Net deferred tax liabilities	$ (253,840)	$ (240,332)

(1) As of December 31, 2015, the net operating loss carryforwards included (i) state net operating loss carryovers of $63.1 million which will begin to expire in 2016, (ii) federal net operating loss carryforwards of $72.0 million which will begin to expire in 2025, and (iii) foreign net operating loss carryforwards of $49.7 million which will begin to expire in 2016.

(2) As of December 31, 2015, the foreign tax credit carryforwards of $25.0 million will expire between 2016 and 2024.

The Company does not accrue U.S. tax for foreign earnings that it considers to be permanently reinvested outside the United States. Consequently, the Company has not provided any U.S. tax on the unremitted earnings of its foreign subsidiaries. As of December 31, 2015, the amount of earnings for which no repatriation tax has been provided was $212.7 million. It is not practicable to estimate the amount of additional tax that might be payable on those earnings if repatriated.

A valuation allowance is required to be established when, based on an evaluation of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Accordingly, as of December 31, 2015 and 2014, the Company had a valuation allowance of $30.9 million and $29.1 million, respectively. The total allowance as of December 31, 2015 consisted of $18.7 million of foreign tax credits, $4.1 million of state net operating loss carryforwards, $6.8 million of foreign net operating loss carryforwards and $1.3 million for the deferred tax assets of a Canadian subsidiary. The allowance as of December 31, 2014 consisted of $16.5 million of foreign tax credits, $3.9 million of state net operating loss carryforwards and $6.7 million of foreign net operating loss carryforwards and $2.0 million for the deferred tax assets of a Canadian subsidiary.

The Company's policy is to recognize interest and penalties related to income tax matters as a component of income tax expense. The liability for unrecognized tax benefits at December 31, 2015 included accrued interest of $0.4 million. Interest expense that is recorded as a tax expense against the liability for unrecognized tax benefits for the years ended December 31, 2015, 2014 and 2013 included interest and penalties of $0.1 million, $0.3 million and $0.3 million, respectively.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(11) INCOME TAXES (Continued)

The changes to unrecognized tax benefits (excluding related penalties and interest) from January 1, 2013 through December 31, 2015, were as follows (in thousands):

	2015	2014	2013
Unrecognized tax benefits as of January 1	$ 2,537	$ 1,304	$ 3,543
Additions to current year tax positions	—	904	210
Additions to prior year tax positions	—	419	—
Settlements	(217)	—	—
Statute expiration	—	—	(2,843)
Foreign currency translation	(256)	(90)	394
Unrecognized tax benefits as of December 31	$ 2,064	$ 2,537	$ 1,304

At December 31, 2015, 2014 and 2013, the Company had recorded $2.1 million, $2.5 million and $1.3 million, respectively, of unrecognized tax benefits that if recognized would affect the annual effective tax rate.

The Company recognizes interest, and penalties if applicable, related to unrecognized tax benefits as a component of income tax expense. The Company had approximately $0.4 million, $0.4 million and $0.2 million for the payment of interest accrued at December 31, 2015, 2014 and 2013, respectively.

The Company files U.S. federal income tax returns as well as income tax returns in various states and foreign jurisdictions. The Company may be subject to examination by the Internal Revenue Service (the "IRS") for calendar years 2012 through 2014. Additionally, any net operating losses that were generated in prior years and utilized in these years may also be subject to examination by the IRS. The Company may also be subject to examinations by state and local revenue authorities for calendar years 2011 through 2014. The Company is currently not under examination by the IRS. The Company has ongoing U.S. state and local jurisdictional audits, as well as Canadian federal and provincial audits, all of which the Company believes will not result in material liabilities.

Due to expiring statute of limitation periods and the resolution of tax audits, the Company believes that total unrecognized tax benefits will decrease by approximately $0.5 million within the next 12 months.

(12) EARNINGS (LOSS) PER SHARE

The following are computations of basic and diluted earnings (loss) per share (in thousands except for per share amounts):

	Years Ended December 31,		
	2015	2014	2013
Numerator for basic and diluted earnings (loss) per share:			
Net income (loss)	$ 44,102	$ (28,328)	$ 95,566
Denominator:			
Weighted basic shares outstanding	58,324	60,311	60,574
Dilutive effect of equity-based compensation awards	110	—	154
Weighted dilutive shares outstanding	58,434	60,311	60,728
Basic earnings (loss) per share	$ 0.76	$ (0.47)	$ 1.58
Diluted earnings (loss) per share	$ 0.76	$ (0.47)	$ 1.57

For the year ended December 31, 2015, the dilutive effect of all then outstanding stock options, restricted stock awards and performance awards is included in the EPS calculations above except for 154,577 of outstanding performance stock awards for which the performance criteria were not attained at that time and 31,656 restricted stock awards which were excluded from the calculation of diluted earnings per share as their inclusion would have an antidilutive effect. As a result of the net loss

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(12) EARNINGS (LOSS) PER SHARE (Continued)

reported for the year ended December 31, 2014, all outstanding stock options, restricted stock awards and performance awards totaling 562,896 were excluded from the calculation of diluted earnings per share as their inclusion would have an antidilutive effect. For the year ended December 31, 2013, the dilutive effect of all then outstanding stock options, restricted stock awards and performance awards is included in the EPS calculations above except for 109,861 outstanding performance stock awards, respectively, for which the performance criteria were not attained at that time.

(13) STOCKHOLDERS' EQUITY

On March 13, 2015, the Company's board of directors increased the size of the Company's current share repurchase program from $150 million to $300 million. The Company has funded and intends to continue to fund the repurchases through available cash resources. The repurchase program authorizes the Company to purchase the Company's common stock on the open market from time to time. The share repurchases have been and will be made in a manner that complies with applicable U.S. securities laws. The number of shares purchased and the timing of the purchases will depend on a number of factors, including share price, cash required for future business plans, trading volume and other conditions. The Company has no obligation to repurchase stock under this program and may suspend or terminate the repurchase program at any time. As of December 31, 2015, the Company had repurchased and retired a total of approximately 3.4 million shares of its common stock for approximately $177.7 million under this program. As of December 31, 2015, an additional $122.3 million remained available for repurchase of shares under this program.

(14) ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in accumulated other comprehensive loss by component and related tax effects for the years ended December 31, 2015, 2014 and 2013 were as follows (in thousands):

	Foreign Currency Translation Adjustments	Unrealized Gains (Losses) on Available-for-Sale Securities	Unfunded Pension Liability	Total
Balance at January 1, 2013	$ 50,627	$ 660	$ (1,655)	$ 49,632
Other comprehensive (loss) income before reclassifications	(70,791)	1,452	482	(68,857)
Amounts reclassified out of accumulated other comprehensive loss	—	—	—	—
Tax effects	—	(208)	(123)	(331)
Other comprehensive (loss) income	(70,791)	1,244	359	(69,188)
Balance at December 31, 2013	$ (20,164)	$ 1,904	$ (1,296)	$ (19,556)
Other comprehensive (loss) income before reclassifications	(88,725)	1,159	(905)	(88,471)
Amounts reclassified out of accumulated other comprehensive loss	—	(3,388)	—	(3,388)
Tax effects	—	325	248	573
Other comprehensive loss	(88,725)	(1,904)	(657)	(91,286)
Balance at December 31, 2014	$ (108,889)	$ —	$ (1,953)	$ (110,842)
Other comprehensive loss before reclassifications	(144,050)	—	(7)	(144,057)
Amounts reclassified out of accumulated other comprehensive loss	—	—	—	—
Tax effects	—	—	7	7
Other comprehensive loss	(144,050)	—	—	(144,050)
Balance at December 31, 2015	$ (252,939)	$ —	$ (1,953)	$ (254,892)

There were no reclassifications out of accumulated other comprehensive loss during the years ended December 31, 2013 and 2015. The amounts reclassified out of accumulated other comprehensive loss into the consolidated statement of income (loss), with presentation location, during the year ended December 31, 2014 were as follows (in thousands):

Comprehensive Loss Components	December 31, 2014	Location
Unrealized holding gains on available-for-sale investments	$ 3,388	Other (expense) income

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(15) STOCK-BASED COMPENSATION AND EMPLOYEE BENEFIT PLANS

Stock-Based Compensation

In 2000, the Company adopted a stock incentive plan (the "2000 Plan"), which provided for awards in the form of incentive stock options, non-qualified stock options, restricted stock awards, performance stock awards and common stock awards. The 2000 Plan expired on April 15, 2010, but as of December 31, 2015, 24,000 options remained outstanding under this plan. These options are fully vested with a weighted average exercise price of $28.05 and will remain outstanding until they are either exercised or expire in accordance with their terms.

In 2010, the Company adopted an equity incentive plan (the "2010 Plan"), which provides for awards of up to 6,000,000 shares of common stock (subject to certain anti-dilution adjustments) in the form of (i) stock options, (ii) stock appreciation rights, (iii) restricted stock, (iv) restricted stock units, and (v) certain other stock-based awards. The Company ceased issuing stock options in 2008, and all awards issued to date under the 2010 Plan have been in the form of restricted stock awards and performance stock awards as described below.

As of December 31, 2015 and 2014, the Company had the following types of stock-based compensation awards outstanding under the 2000 Plan and the 2010 Plan (collectively, the "Plans"): stock options, restricted stock awards and performance stock awards. The stock options generally become exercisable up to five years from the date of grant, subject to certain employment requirements, and terminate 10 years from the date of grant. The restricted stock awards generally vest over three to five years subject to continued employment. The performance stock awards vest depending on the satisfaction of certain performance criteria and continued service conditions as described below.

Total stock-based compensation cost charged to selling, general and administrative expenses for the years ended December 31, 2015, 2014 and 2013 was $8.6 million, $8.8 million and $9.0 million, respectively. The total income tax benefit recognized in the consolidated statements of income from stock-based compensation was $2.3 million, $1.9 million and $3.2 million for the years ended December 31, 2015, 2014 and 2013, respectively. The expected per annum forfeiture rates used to calculate compensation expense were 6% for all employees.

Restricted Stock Awards

The following information relates to restricted stock awards that have been granted to employees and directors under the Company's Plans. The restricted stock awards are not transferable until vested and the restrictions generally lapse upon the achievement of continued employment over a three-to-five-year period or service as a director until the following annual meeting of shareholders. The fair value of each restricted stock grant is based on the closing price of the Company's common stock on the date of grant and is amortized to expense over its vesting period.

The following table summarizes information about restricted stock awards for the year ended December 31, 2015:

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Unvested at January 1, 2015	383,021	$ 56.51
Granted	153,934	54.16
Vested	(128,989)	55.75
Forfeited	(45,348)	56.46
Unvested at December 31, 2015	362,618	$ 55.79

As of December 31, 2015, there was $11.5 million of total unrecognized compensation cost arising from restricted stock awards under the Company's Plans. This cost is expected to be recognized over a weighted average period of 3.1 years. The total fair value of restricted stock vested during 2015, 2014 and 2013 was $6.9 million, $9.4 million and $4.4 million, respectively.

Performance Stock Awards

The following information relates to performance stock awards that have been granted to employees under the Company's Plans. The compensation committee of the Company's board of directors established two-year performance targets which could potentially be achieved in the year granted or one year thereafter. Performance stock awards are subject to performance criteria established by the compensation committee of the Company's board of directors prior to or at the date of grant. The vesting of

(15) STOCK-BASED COMPENSATION AND EMPLOYEE BENEFIT PLANS (Continued)

the performance stock awards is based on achieving such targets typically based on revenue, Adjusted EBITDA margin, Return on Invested Capital ("ROIC") percentage, and Total Recordable Incident Rate. In addition performance stock awards include continued service conditions.

The fair value of each performance stock award is based on the closing price of the Company's common stock on the date of grant and is amortized to expense over the service period if achievement of performance measures is then considered probable. The expected forfeiture rate used to calculate compensation expense was 6% for all employees.

As of December 31, 2015, management determined that none of the performance criteria were achieved with respect to the performance stock awards granted in 2015 and as a result no stock-based compensation expense was recorded. For the performance stock awards granted in 2014, management determined that one of the four performance criteria was achieved and as a result the Company recognized stock based compensation on 25% of the original award, or $1.0 million, within selling, general and administrative expenses. These awards will vest over the remaining requisite service condition.

The following table summarizes information about performance stock awards for the year ended December 31, 2015:

Performance Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Unvested at January 1, 2015	143,875	$ 60.94
Granted	168,186	56.40
Vested	(11,656)	54.28
Forfeited	(113,131)	61.18
Unvested at December 31, 2015	187,274	$ 57.13

As of December 31, 2015, there was $0.6 million of total unrecognized compensation cost arising from non-vested compensation related to performance stock awards then deemed probable of vesting under the Company's Plans. The total fair value of performance awards vested during 2015 was $0.6 million. During 2014 and 2013 no performance awards vested.

Common Stock Awards

In the years ended December 31, 2015 and 2014, the Company did not issue any shares of common stock without restrictions under the Company's Plans.

Employee Benefit Plans

As of December 31, 2015, the Company has responsibility for a defined benefit plan that covered 15 active non-supervisory Canadian employees. For each of the years ended December 31, 2015, 2014 and 2013, net periodic pension cost was $0.3 million. At December 31, 2015, the fair value of the Company's plan assets was $8.4 million. The fair value of $6.6 million of these plan assets was considered a Level 1 measure and the fair value of $1.8 million of these plan assets was considered a Level 2 measure, according to the fair value hierarchy. At December 31, 2014, the fair value of the Company's plan assets was $9.4 million. The fair value of $7.5 million of these plan assets was considered a Level 1 measure and the fair value of $1.9 million of these plan assets was considered a Level 2 measure, according to the fair value hierarchy. As of December 31, 2015 and 2014, the projected benefit obligation was $10.0 million and $11.2 million, respectively.

The Company also has a profit-sharing plan under Section 401(k) of the Internal Revenue Code covering substantially all U.S. employees and a Canadian registered retired savings plan covering all Canadian employees. Both plans allow employees to make contributions up to a specified percentage of their compensation. The Company makes discretionary partial matching contributions established annually by the Board of Directors. The Company expensed $9.2 million, $12.0 million, and $8.9 million for the years ended December 31, 2015, 2014 and 2013, respectively, related to the U.S. plan and $3.0 million, $3.4 million and $3.1 million for the years ended December 31, 2015, 2014 and 2013, respectively, related to the Canadian plan.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(16) COMMITMENTS AND CONTINGENCIES

Legal and Administrative Proceedings

The Company and its subsidiaries are subject to legal proceedings and claims arising in the ordinary course of business. Actions filed against the Company arise from commercial and employment-related claims including alleged class actions related to sales practices and wage and hour claims. The plaintiffs in these actions may be seeking damages or injunctive relief or both. These actions are in various jurisdictions and stages of proceedings, and some are covered in part by insurance. In addition, the Company's waste management services operations are regulated by federal, state, provincial and local laws enacted to regulate discharge of materials into the environment, remediation of contaminated soil and groundwater or otherwise protect the environment. This ongoing regulation results in the Company frequently becoming a party to legal or administrative proceedings involving all levels of governmental authorities and other interested parties. The issues involved in such proceedings generally relate to alleged violations of existing permits and licenses or alleged responsibility under federal or state Superfund laws to remediate contamination at properties owned either by the Company or by other parties ("third party sites") to which either the Company or the prior owners of certain of the Company's facilities shipped wastes.

At December 31, 2015 and December 31, 2014, the Company had recorded reserves of $21.9 million and $33.6 million, respectively, in the Company's financial statements for actual or probable liabilities related to the legal and administrative proceedings in which the Company was then involved, the principal of which are described below. At December 31, 2015 and December 31, 2014, the Company also believed that it was reasonably possible that the amount of these potential liabilities could be as much as $1.9 million and $2.9 million more, respectively. The Company periodically adjusts the aggregate amount of these reserves when actual or probable liabilities are paid or otherwise discharged, new claims arise, or additional relevant information about existing or probable claims becomes available. As of December 31, 2015 and December 31, 2014, the $21.9 million and $33.6 million, respectively, of reserves consisted of (i) $18.9 million and $27.7 million, respectively, related to pending legal or administrative proceedings, including Superfund liabilities, which were included in remedial liabilities on the consolidated balance sheets, and (ii) $3.0 million and $5.9 million, respectively, primarily related to federal, state and provincial enforcement actions, which were included in accrued expenses on the consolidated balance sheets.

As of December 31, 2015, the principal legal and administrative proceedings in which the Company was involved, or which had been terminated during 2015, were as follows:

Ville Mercier. In September 2002, the Company acquired the stock of a subsidiary (the "Mercier Subsidiary") which owns a hazardous waste incinerator in Ville Mercier, Quebec (the "Mercier Facility"). The property adjacent to the Mercier Facility, which is also owned by the Mercier Subsidiary, is now contaminated as a result of actions dating back to 1968, when the Government of Quebec issued to a company unrelated to the Mercier Subsidiary two permits to dump organic liquids into lagoons on the property. In 1999, Ville Mercier and three neighboring municipalities filed separate legal proceedings against the Mercier Subsidiary and the Government of Quebec. In 2012, the municipalities amended their existing statement of claim to seek $2.9 million (Cdn) in general damages and $10.0 million (Cdn) in punitive damages, plus interest and costs, as well as injunctive relief. Both the Government of Quebec and the Company have filed summary judgment motions against the municipalities. The parties are currently attempting to negotiate a resolution and hearings on the motions have been delayed. In September 2007, the Quebec Minister of Sustainable Development, Environment and Parks issued a Notice pursuant to Section 115.1 of the Environment Quality Act, superseding Notices issued in 1992, which are the subject of the pending litigation. The more recent Notice notifies the Mercier Subsidiary that, if the Mercier Subsidiary does not take certain remedial measures at the site, the Minister intends to undertake those measures at the site and claim direct and indirect costs related to such measures. The Company has accrued for costs expected to be incurred relative to the resolution of this matter and believes this matter will not have future material effect on its financial position or results of operations.

Refinery Incident. In September 2014, a customer filed suit against the Company and two other contractors and their respective insurers seeking to be named as an additional insured on the Company's and the other contractors' liability policies for an April 2013 industrial fire that occurred at the customer's refining facility. As of December 31, 2015 the Company and its insurers have resolved the dispute relating to the customer's additional insured status and the customer has agreed to indemnify the Company from any additional losses relating to the matter. The Company believes that this matter is currently resolved and will not have any future material effect on its financial position or results of operations.

Safety-Kleen Legal Proceedings. On December 28, 2012, the Company acquired Safety-Kleen, Inc. ("Safety-Kleen") and thereby became subject to the legal proceedings in which Safety-Kleen was a party on that date. In addition to certain Superfund proceedings in which Safety-Kleen has been named as a potentially responsible party as described below under

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(16) COMMITMENTS AND CONTINGENCIES (Continued)

"Superfund Proceedings," the principal such legal proceedings involving Safety-Kleen which were outstanding as of December 31, 2015 were as follows:

Product Liability Cases. Safety-Kleen is named as a defendant in various lawsuits that are currently pending in various courts and jurisdictions throughout the United States, including approximately 58 proceedings (excluding cases which have been settled but not formally dismissed) as of December 31, 2015, wherein persons claim personal injury resulting from the use of Safety-Kleen's parts cleaning equipment or cleaning products. These proceedings typically involve allegations that the solvent used in Safety-Kleen's parts cleaning equipment contains contaminants and/or that Safety-Kleen's recycling process does not effectively remove the contaminants that become entrained in the solvent during their use. In addition, certain claimants assert that Safety-Kleen failed to warn adequately the product user of potential risks, including an historic failure to warn that solvent contains trace amounts of toxic or hazardous substances such as benzene. Safety-Kleen maintains insurance that it believes will provide coverage for these claims (over amounts accrued for self-insured retentions and deductibles in certain limited cases), except for punitive damages to the extent not insurable under state law or excluded from insurance coverage. Safety-Kleen believes that these claims lack merit and has historically vigorously defended, and intends to continue to vigorously defend, itself and the safety of its products against all of these claims. Such matters are subject to many uncertainties and outcomes are not predictable with assurance. Consequently, Safety-Kleen is unable to ascertain the ultimate aggregate amount of monetary liability or financial impact with respect to these matters as of December 31, 2015. From January 1, 2015 to December 31, 2015, 30 product liability claims were settled or dismissed. Due to the nature of these claims and the related insurance, the Company did not incur any expense as Safety-Kleen's insurance provided coverage in full for all such claims. Safety-Kleen may be named in similar, additional lawsuits in the future, including claims for which insurance coverage may not be available.

Fee Class Action Claims. In October 2010, two customers filed a complaint, individually and on behalf of all similarly situated customers in the State of Alabama, alleging that Safety-Kleen improperly assessed fuel surcharges and extended area service fees. In 2012, similar lawsuits were filed by the same law firm in California and Missouri. On January 15, 2015, the Company reached a tentative settlement of the pending class action lawsuits, which were broadened to include similar claims on behalf of customers in Florida, West Virginia and Arkansas. The settlement was approved by the court in a fairness hearing in June 2015. The settlement amount paid to class claimants was not material. The matter has been dismissed.

Superfund Proceedings

The Company has been notified that either the Company (which, since December 28, 2012, includes Safety-Kleen) or the prior owners of certain of the Company's facilities for which the Company may have certain indemnification obligations have been identified as potentially responsible parties ("PRPs") or potential PRPs in connection with 128 sites which are subject to or
are proposed to become subject to proceedings under federal or state Superfund laws. Of the 128 sites, two (the Wichita Facility and the BR Facility described below) involve facilities that are now owned by the Company and 126 involve third party sites to which either the Company or the prior owners of certain of the Company's facilities shipped wastes. Of the 126 third party sites, 32 are now settled, 16 are currently requiring expenditures on remediation and 78 are not currently requiring expenditures on remediation.

In connection with each site, the Company has estimated the extent, if any, to which it may be subject, either directly or as a result of any indemnification obligations, for cleanup and remediation costs, related legal and consulting costs associated with PRP investigations, settlements, and related legal and administrative proceedings. The amount of such actual and potential
liability is inherently difficult to estimate because of, among other relevant factors, uncertainties as to the legal liability (if any) of the Company or the prior owners of certain of the Company's facilities to contribute a portion of the cleanup costs, the assumptions that must be made in calculating the estimated cost and timing of remediation, the identification of other PRPs and their respective capability and obligation to contribute to remediation efforts, and the existence and legal standing of indemnification agreements (if any) with prior owners, which may either benefit the Company or subject the Company to potential indemnification obligations. In addition to the Wichita Property and the BR Facility, Clean Harbors believes its potential liability could exceed $100,000 at 10 of the 126 third party sites.

Wichita Property. The Company acquired in 2002 as part of the CSD assets a service center located in Wichita, Kansas (the "Wichita Property"). The Wichita Property is one of several properties located within the boundaries of a 1,400 acre state-designated Superfund site in an old industrial section of Wichita known as the North Industrial Corridor Site. Along with numerous other PRPs, the former owner executed a consent decree relating to such site with the U.S. Environmental Protection Agency (the "EPA"), and the Company is continuing an ongoing remediation program for the Wichita Property in accordance

(16) COMMITMENTS AND CONTINGENCIES (Continued)

with that consent decree. The Company also acquired rights under an indemnification agreement between the former owner and an earlier owner of the Wichita Property. The Company filed suit against the earlier owner in July of 2015 to recover costs incurred during the cleanup of the property.

BR Facility. The Company acquired in 2002 a former hazardous waste incinerator and landfill in Baton Rouge (the "BR Facility"), for which operations had been previously discontinued by the prior owner. In September 2007, the EPA issued a special notice letter to the Company related to the Devil's Swamp Lake Site ("Devil's Swamp") in East Baton Rouge Parish, Louisiana. Devil's Swamp includes a lake located downstream of an outfall ditch where wastewater and stormwater have been discharged, and Devil's Swamp is proposed to be included on the National Priorities List due to the presence of Contaminants of Concern ("COC") cited by the EPA. These COCs include substances of the kind found in wastewater and storm water discharged from the BR Facility in past operations. The EPA originally requested COC generators to submit a good faith offer to conduct a remedial investigation feasibility study directed towards the eventual remediation of the site. The Company is currently performing corrective actions at the BR Facility under an order issued by the Louisiana Department of Environmental Quality, and has begun conducting the remedial investigation and feasibility study under an order issued by the EPA. The Company cannot presently estimate the potential additional liability for the Devil's Swamp cleanup until a final remedy is selected by the EPA.

Third Party Sites. Of the 126 third party sites at which the Company has been notified it is a PRP or potential PRP or may have indemnification obligations, Clean Harbors has an indemnification agreement at 11 of these sites with ChemWaste, a former subsidiary of Waste Management, Inc., and at six additional of these third party sites, Safety-Kleen has a similar indemnification agreement with McKesson Corporation. These agreements indemnify the Company (which now includes Safety-Kleen) with respect to any liability at the 17 sites for waste disposed prior to the Company's (or Safety-Kleen's) acquisition of the former subsidiaries of Waste Management or McKesson which had shipped wastes to those sites. Accordingly, Waste Management or McKesson are paying all costs of defending those subsidiaries in those 17 cases, including legal fees and settlement costs. However, there can be no guarantee that the Company's ultimate liabilities for those sites will not exceed the amount recorded or that indemnities applicable to any of these sites will be available to pay all or a portion of related costs. Except for the indemnification agreements which the Company holds from ChemWaste and McKesson, the Company does not have an indemnity agreement with respect to any of the 126 third party sites discussed above.

Federal, State and Provincial Enforcement Actions

From time to time, the Company pays fines or penalties in regulatory proceedings relating primarily to waste treatment, storage or disposal facilities. As of December 31, 2015 and 2014, there were six and four proceedings, respectively, for which the Company reasonably believed that the sanctions could equal or exceed $100,000. The Company believes that the fines or other penalties in these or any of the other regulatory proceedings will, individually or in the aggregate, not have a material effect on its financial condition, results of operations or cash flows.

Leases

The Company leases facilities, service centers and personal property under certain operating leases. Some of these lease agreements contain an escalation clause for increased taxes and operating expenses and are renewable at the option of the Company. Lease terms range from 1 to 20 years. The following is a summary of future minimum payments under operating leases that have initial or remaining noncancelable lease terms in excess of one year at December 31, 2015 (in thousands):

Year	Total Operating Leases
2016	$ 37,064
2017	29,198
2018	21,926
2019	17,997
2020	12,406
Thereafter	24,387
Total minimum lease payments	$ 142,978

During the years ended December 31, 2015, 2014 and 2013, rent expense including short-term rentals was approximately $135.5 million, $129.6 million, and $124.4 million, respectively.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(16) COMMITMENTS AND CONTINGENCIES (Continued)

Other Contingencies

Under the Company's insurance programs, coverage is obtained for catastrophic exposures, as well as those risks required to be insured by law or contract. The Company's policy is to retain a significant portion of certain expected losses related primarily to workers' compensation, health insurance, comprehensive general, environmental impairment and vehicle liability.

Provisions for losses expected under these programs are recorded based upon the Company's estimates of the aggregate liability for claims. The deductible per participant per year for the health insurance policy is $0.3 million. The deductible per occurrence for workers' compensation is $1.0 million, general liability is $2.0 million and vehicle liability is $2.0 million. The retention per claim for the environmental impairment policy is $1.0 million. At December 31, 2015 and 2014, the Company had accrued $34.8 million and $34.0 million, respectively, for its self-insurance liabilities (exclusive of health insurance) using a risk-free discount rate of 1.29% and 1.28%, respectively. Actual expenditures in future periods can differ materially from accruals based on estimates.

Anticipated payments at December 31, 2015 for each of the next five years and thereafter are as follows (in thousands):

Years ending December 31,		
2016	$	14,735
2017		7,383
2018		4,948
2019		3,539
2020		1,829
Thereafter		3,109
Undiscounted self-insurance liabilities		35,543
Less: Discount		732
Total self-insurance liabilities (included in accrued expenses)	$	34,811

(17) SEGMENT REPORTING

Segment reporting is prepared on the same basis that the Company's chief executive officer, who is the Company's chief operating decision maker, manages the business, makes operating decisions and assesses performance. The Company's operations are managed in six reportable segments based primarily upon the nature of the various operations and services provided: Technical Services, Industrial and Field Services which consists of the Industrial Services and Field Services operating segments, Kleen Performance Products, SK Environmental Services, Lodging Services and Oil and Gas Field Services.

Third party revenue is revenue billed to outside customers by a particular segment. Direct revenue is revenue allocated to the segment providing the product or service. Intersegment revenues represent the sharing of third party revenues among the segments based on products and services provided by each segment as if the products and services were sold directly to the third party. The intersegment revenues are shown net. The negative intersegment revenues are due to more transfers out of customer revenues to other segments than transfers in of customer revenues from other segments. The operations not managed through the Company’s six reportable segments are recorded as “Corporate Items.” Corporate Items revenues consist of two different operations for which the revenues are insignificant. Corporate Items cost of revenues represents certain central services that are not allocated to the six segments for internal reporting purposes. Corporate Items selling, general and administrative expenses include typical corporate items such as legal, accounting and other items of a general corporate nature that are not allocated to the Company’s six reportable segments. Performance of the segments is evaluated on several factors, of which the primary financial measure is “Adjusted EBITDA,” which consists of net income (loss) plus accretion of environmental liabilities, depreciation and amortization, net interest expense, provision for income taxes, other non-cash charges (including goodwill impairment charge) not deemed representative of fundamental segment results and excludes other expense (income). Transactions between the segments are accounted for at the Company’s best estimate based on similar transactions with outside customers.

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(17) SEGMENT REPORTING (Continued)

The following table reconciles third party revenues to direct revenues for the years ended December 31, 2015, 2014 and 2013 (in thousands).

	For the Year Ended December 31, 2015							
	Technical Services	Industrial and Field Services	Kleen Performance Products	SK Environmental Services	Lodging Services	Oil and Gas Field Services	Corporate Items	Totals
Third party revenues	$ 991,410	$ 957,337	$ 386,824	$ 674,102	$ 89,060	$ 175,946	$ 458	$ 3,275,137
Intersegment revenues, net	144,084	(32,982)	(79,991)	(39,241)	2,496	5,634	—	—
Corporate Items, net	3,586	(756)	(8)	3	157	200	(3,182)	—
Direct revenues	$ 1,139,080	$ 923,599	$ 306,825	$ 634,864	$ 91,713	$ 181,780	$ (2,724)	$ 3,275,137

	For the Year Ended December 31, 2014							
	Technical Services	Industrial and Field Services	Kleen Performance Products	SK Environmental Services	Lodging Services	Oil and Gas Field Services	Corporate Items	Totals
Third party revenues	$ 1,043,267	$ 681,779	$ 533,587	$ 667,320	$ 172,218	$ 303,189	$ 276	$ 3,401,636
Intersegment revenues, net	156,543	(42,681)	(201,859)	80,477	2,434	5,086	—	—
Corporate Items, net	5,573	271	(5)	(58)	80	(5)	(5,856)	—
Direct revenues	$ 1,205,383	$ 639,369	$ 331,723	$ 747,739	$ 174,732	$ 308,270	$ (5,580)	$ 3,401,636

	For the Year Ended December 31, 2013							
	Technical Services	Industrial and Field Services	Kleen Performance Products	SK Environmental Services	Lodging Services	Oil and Gas Field Services	Corporate Items	Totals
Third party revenues	$ 1,023,926	$ 708,523	$ 528,636	$ 665,008	$ 208,545	$ 383,959	$ (8,941)	$ 3,509,656
Intersegment revenues, net	120,382	(44,717)	(193,009)	107,007	3,450	6,887	—	—
Corporate Items, net	3,507	(217)	—	84	390	(341)	(3,423)	—
Direct revenues	$ 1,147,815	$ 663,589	$ 335,627	$ 772,099	$ 212,385	$ 390,505	$ (12,364)	$ 3,509,656

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(17) SEGMENT REPORTING (Continued)

The following table presents Adjusted EBITDA information used by management by reported segment (in thousands). The Company does not allocate interest expense, income taxes, depreciation, amortization, accretion of environmental liabilities, other non-cash charges not deemed representative of fundamental segment results and other expense (income) to its segments.

	For the Year Ended December 31,		
	2015	2014	2013
Adjusted EBITDA:			
Technical Services	$ 291,737	$ 328,130	$ 285,520
Industrial and Field Services	157,500	87,591	96,804
Kleen Performance Products	32,189	51,561	57,003
SK Environmental Services	140,073	113,986	112,722
Lodging Services	16,478	61,438	80,358
Oil and Gas Field Services	(827)	40,114	67,855
Corporate Items	(132,983)	(160,901)	(190,157)
Total	504,167	521,919	510,105
Reconciliation to Consolidated Statements of Income (Loss):			
Pre-tax, non-cash acquisition accounting inventory adjustment	—	—	13,559
Accretion of environmental liabilities	10,402	10,612	11,541
Depreciation and amortization	274,194	276,083	264,449
Goodwill impairment charge	31,992	123,414	—
Income from operations	187,579	111,810	220,556
Other expense (income)	1,380	(4,380)	(1,705)
Interest expense, net of interest income	76,553	77,668	78,376
Income from operations before provision for income taxes	$ 109,646	$ 38,522	$ 143,885

Revenue, property, plant and equipment and intangible assets outside of the United States

For the year ended December 31, 2015, the Company generated $2,576.2 million or 78.7% of revenues in the United States and Puerto Rico, $695.0 million or 21.2% of revenues in Canada, and less than 1.0% of revenues in other international locations. For the year ended December 31, 2014, the Company generated $2,414.6 million or 71.0% of revenues in the United States and Puerto Rico, $982.1 million or 28.9% of revenues in Canada, and less than 1.0% of revenues in other international locations. For the year ended December 31, 2013, the Company generated $2,376.2 million or 67.7% of revenues in the United States and Puerto Rico, $1,125.0 million or 32.1% of revenues in Canada, and less than 1.0% of revenues in other international locations.

As of December 31, 2015, the Company had property, plant and equipment, net of depreciation and amortization of $1,532.5 million, and permits and other intangible assets of $506.8 million. Of these totals, $449.3 million or 29.3% of property, plant and equipment and $71.7 million or 14.2% of permits and other intangible assets were in Canada, with the balance being in the United States and Puerto Rico (except for insignificant assets in other foreign countries). As of December 31, 2014, the Company had property, plant and equipment, net of depreciation and amortization of $1,558.8 million, and permits and other intangible assets of $530.1 million. Of these totals, $587.4 million or 37.7% of property, plant and equipment and $94.2 million or 17.8% of permits and other intangible assets were in Canada, with the balance being in the United States and Puerto Rico (except for insignificant assets in other foreign countries).

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(17) SEGMENT REPORTING (Continued)

The following table presents assets by reported segment and in the aggregate (in thousands).

	December 31, 2015	December 31, 2014
Property, plant and equipment, net		
Technical Services	$ 483,425	$ 412,323
Industrial and Field Services	237,660	245,115
Kleen Performance Products	193,855	201,451
SK Environmental Services	264,539	240,078
Lodging Services	105,208	141,965
Oil and Gas Field Services	156,286	215,574
Corporate Items	91,494	102,328
Total property, plant and equipment, net	$ 1,532,467	$ 1,558,834
Goodwill and Permits and other intangibles, net		
Technical Services		
Goodwill	$ 49,267	$ 50,092
Permits and other intangibles, net	73,601	74,870
Total Technical Services	122,868	124,962
Industrial and Field Services		
Goodwill	105,286	109,214
Permits and other intangibles, net	14,649	17,801
Total Industrial and Field Services	119,935	127,015
Kleen Performance Products		
Goodwill	49,755	50,883
Permits and other intangibles, net	140,410	151,041
Total Kleen Performance Products	190,165	201,924
SK Environmental Services		
Goodwill	216,589	173,873
Permits and other intangibles, net	256,251	252,897
Total SK Environmental Services	472,840	426,770
Lodging Services		
Goodwill	32,208	34,863
Permits and other intangibles, net	7,045	10,744
Total Lodging Services	39,253	45,607
Oil and Gas Field Services		
Goodwill	—	33,744
Permits and other intangibles, net	14,862	22,727
Total Oil and Gas Field Services	14,862	56,471
Total	$ 959,923	$ 982,749

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(17) SEGMENT REPORTING (Continued)

The following table presents the total assets by reported segment (in thousands).

	December 31, 2015	December 31, 2014	December 31, 2013
Technical Services	$ 800,060	$ 756,169	$ 699,675
Industrial and Field Services	368,858	392,652	410,233
Kleen Performance Products	492,483	538,921	642,901
SK Environmental Services	805,488	731,072	774,756
Lodging Services	181,357	231,782	239,056
Oil and Gas Field Services	244,210	361,223	381,057
Corporate Items	538,972	677,604	788,752
Total	$ 3,431,428	$ 3,689,423	$ 3,936,430

The following table presents the total assets by geographical area (in thousands).

	December 31, 2015	December 31, 2014	December 31, 2013
United States	$ 2,575,746	$ 2,557,639	$ 2,667,438
Canada	851,949	1,128,458	1,266,505
Other foreign	3,733	3,326	2,487
Total	$ 3,431,428	$ 3,689,423	$ 3,936,430

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES

The 2020 Notes and the 2021 Notes are guaranteed by substantially all of the Company's subsidiaries organized in the United States. Each guarantor for the 2020 Notes and the 2021 Notes is a 100% owned subsidiary of Clean Harbors, Inc. and its guarantee is both full and unconditional and joint and several. The guarantees are, however, subject to customary release provisions under which, in particular, the guarantee of any of our domestic restricted subsidiaries will be released if we sell such subsidiary to an unrelated third party in accordance with the terms of the indenture which governs the notes. The 2020 Notes and the 2021 Notes are not guaranteed by the Company's Canadian or other foreign subsidiaries. The following supplemental condensed consolidating financial information for the parent company, the guarantor subsidiaries and the non-guarantor subsidiaries respectively, is presented in conformity with the requirements of Rule 3-10 of SEC Regulation S-X ("Rule 3-10").

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES (Continued)

Following is the condensed consolidating balance sheet at December 31, 2015 (in thousands):

	Clean Harbors, Inc.	U.S. Guarantor Subsidiaries	Foreign Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Assets:					
Cash and cash equivalents	$ 11,017	$ 83,479	$ 90,212	$ —	$ 184,708
Intercompany receivables	164,709	213,243	39,804	(417,756)	—
Accounts receivable, net	—	404,580	91,424	—	496,004
Other current assets	—	179,969	60,515	—	240,484
Property, plant and equipment, net	—	1,082,466	450,001	—	1,532,467
Investments in subsidiaries	2,547,307	522,067	—	(3,069,374)	—
Intercompany debt receivable	—	260,957	3,701	(264,658)	—
Goodwill	—	367,306	85,799	—	453,105
Permits and other intangibles, net	—	435,080	71,738	—	506,818
Other long-term assets	1,068	10,274	6,500	—	17,842
Total assets	$ 2,724,101	$ 3,559,421	$ 899,694	$ (3,751,788)	$ 3,431,428
Liabilities and Stockholders' Equity:					
Current liabilities	$ 20,813	$ 424,588	$ 71,719	$ —	$ 517,120
Intercompany payables	220,762	195,287	1,707	(417,756)	—
Closure, post-closure and remedial liabilities, net	—	153,190	14,656	—	167,846
Long-term obligations	1,382,543	—	—	—	1,382,543
Capital lease obligations, net	—	—	—	—	—
Intercompany debt payable	3,701	—	260,957	(264,658)	—
Other long-term liabilities	—	239,049	28,588	—	267,637
Total liabilities	1,627,819	1,012,114	377,627	(682,414)	2,335,146
Stockholders' equity	1,096,282	2,547,307	522,067	(3,069,374)	1,096,282
Total liabilities and stockholders' equity	$ 2,724,101	$ 3,559,421	$ 899,694	$ (3,751,788)	$ 3,431,428

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES (Continued)

Following is the condensed consolidating balance sheet at December 31, 2014 (in thousands):

	Clean Harbors, Inc.	U.S. Guarantor Subsidiaries	Foreign Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Assets:					
Cash and cash equivalents	$ 1,006	$ 154,147	$ 91,726	$ —	$ 246,879
Intercompany receivables	133,219	156,920	39,724	(329,863)	—
Accounts receivable, net	—	414,205	142,926	—	557,131
Other current assets	—	241,232	81,191	—	322,423
Property, plant and equipment, net	—	970,757	588,077	—	1,558,834
Investments in subsidiaries	2,694,727	663,191	—	(3,357,918)	—
Intercompany debt receivable	—	327,634	3,701	(331,335)	—
Goodwill	—	324,930	127,739	—	452,669
Permits and other intangibles, net	—	435,906	94,174	—	530,080
Other long-term assets	1,946	12,959	6,502	—	21,407
Total assets	$ 2,830,898	$ 3,701,881	$ 1,175,760	$ (4,019,116)	$ 3,689,423
Liabilities and Stockholders' Equity:					
Current liabilities	$ 20,820	$ 444,059	$ 107,592	$ —	$ 572,471
Intercompany payables	163,361	164,231	2,271	(329,863)	—
Closure, post-closure and remedial liabilities, net	—	158,622	25,109	—	183,731
Long-term obligations	1,380,145	—	—	—	1,380,145
Capital lease obligations, net	—	—	—	—	—
Intercompany debt payable	3,701	—	327,634	(331,335)	—
Other long-term liabilities	—	240,242	49,963	—	290,205
Total liabilities	1,568,027	1,007,154	512,569	(661,198)	2,426,552
Stockholders' equity	1,262,871	2,694,727	663,191	(3,357,918)	1,262,871
Total liabilities and stockholders' equity	$ 2,830,898	$ 3,701,881	$ 1,175,760	$ (4,019,116)	$ 3,689,423

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES (Continued)

Following is the consolidating statement of income (loss) for the year ended December 31, 2015 (in thousands):

	Clean Harbors, Inc.	U.S. Guarantor Subsidiaries	Foreign Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Revenues					
Service revenues	$ —	$ 2,111,086	$ 692,216	$ (59,030)	$ 2,744,272
Product revenues	—	458,314	83,970	(11,419)	530,865
Total revenues	—	2,569,400	776,186	(70,449)	3,275,137
Cost of revenues (exclusive of items shown separately below)					
Service cost of revenues	5	1,415,435	542,497	(59,030)	1,898,907
Product cost of revenues	—	410,128	59,190	(11,419)	457,899
Total cost of revenues	5	1,825,563	601,687	(70,449)	2,356,806
Selling, general and administrative expenses	101	329,069	84,994	—	414,164
Accretion of environmental liabilities	—	9,209	1,193	—	10,402
Depreciation and amortization	—	184,017	90,177	—	274,194
Goodwill impairment charge	—	4,164	27,828	—	31,992
(Loss) income from operations	(106)	217,378	(29,693)	—	187,579
Other income (loss)	—	491	(1,871)	—	(1,380)
Interest (expense) income, net	(78,621)	1,860	208	—	(76,553)
Equity in earnings of subsidiaries, net of tax	91,339	(47,141)	—	(44,198)	—
Intercompany interest income (expense)	—	23,156	(23,156)	—	—
Income before (benefit) provision for income taxes	12,612	195,744	(54,512)	(44,198)	109,646
(Benefit) provision for income taxes	(31,490)	104,405	(7,371)	—	65,544
Net income (loss)	44,102	91,339	(47,141)	(44,198)	44,102
Other comprehensive loss	(144,050)	(144,050)	(93,983)	238,033	(144,050)
Comprehensive loss	$ (99,948)	$ (52,711)	$ (141,124)	$ 193,835	$ (99,948)

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES (Continued)

Following is the consolidating statement of (loss) income for the year ended December 31, 2014 (in thousands):

	Clean Harbors, Inc.	U.S. Guarantor Subsidiaries	Foreign Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Revenues					
Service revenues	—	1,786,695	876,085	(22,984)	2,639,796
Product revenues	—	619,802	148,671	(6,633)	761,840
Total revenues	—	2,406,497	1,024,756	(29,617)	3,401,636
Cost of revenues (exclusive of items shown separately below)					
Service cost of revenues	—	1,172,181	641,180	(22,984)	1,790,377
Product cost of revenues	—	538,671	119,381	(6,633)	651,419
Total cost of revenues	—	1,710,852	760,561	(29,617)	2,441,796
Selling, general and administrative expenses	114	321,069	116,738	—	437,921
Accretion of environmental liabilities	—	9,240	1,372	—	10,612
Depreciation and amortization	—	173,447	102,636	—	276,083
Goodwill impairment charge	—	105,466	17,948	—	123,414
(Loss) income from operations	(114)	86,423	25,501	—	111,810
Other income	—	3,369	1,011	—	4,380
Interest (expense) income, net	(78,570)	800	102	—	(77,668)
Equity in earnings of subsidiaries, net of tax	18,882	(9,031)	—	(9,851)	—
Intercompany dividend income	—	—	6,238	(6,238)	—
Intercompany interest income (expense)	—	28,596	(28,596)	—	—
Income before (benefit) provision for income taxes	(59,802)	110,157	4,256	(16,089)	38,522
(Benefit) provision for income taxes	(31,474)	91,275	7,049	—	66,850
Net (loss) income	(28,328)	18,882	(2,793)	(16,089)	(28,328)
Other comprehensive loss	(91,286)	(91,286)	(37,157)	128,443	(91,286)
Comprehensive loss	$ (119,614)	$ (72,404)	$ (39,950)	$ 112,354	$ (119,614)

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES (Continued)

Following is the consolidating statement of income for the year ended December 31, 2013 (in thousands):

	Clean Harbors, Inc.	U.S. Guarantor Subsidiaries	Foreign Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Revenues					
Service revenues	—	1,757,663	984,122	(12,580)	2,729,205
Product revenues	—	611,548	172,500	(3,597)	780,451
Total revenues	—	2,369,211	1,156,622	(16,177)	3,509,656
Cost of revenues (exclusive of items shown separately below)					
Service cost of revenues	—	1,190,419	696,609	(12,580)	1,874,448
Product cost of revenues	—	524,318	147,464	(3,597)	668,185
Total cost of revenues	—	1,714,737	844,073	(16,177)	2,542,633
Selling, general and administrative expenses	109	353,215	117,153	—	470,477
Accretion of environmental liabilities	—	9,935	1,606	—	11,541
Depreciation and amortization	—	170,041	94,408	—	264,449
(Loss) income from operations	(109)	121,283	99,382	—	220,556
Other income	—	1,655	50	—	1,705
Loss on early extinguishment of debt	—	—	—	—	—
Interest (expense) income, net	(79,017)	236	405	—	(78,376)
Equity in earnings of subsidiaries, net of tax	143,042	42,741	—	(185,783)	—
Intercompany dividend income (expense)	—	—	13,292	(13,292)	—
Intercompany interest income (expense)	—	41,695	(41,695)	—	—
Income before (benefit) provision for income taxes	63,916	207,610	71,434	(199,075)	143,885
(Benefit) provision for income taxes	(31,650)	64,568	15,401	—	48,319
Net income	95,566	143,042	56,033	(199,075)	95,566
Other comprehensive (loss) income	(69,188)	(69,188)	39,519	29,669	(69,188)
Comprehensive income	$ 26,378	$ 73,854	$ 95,552	$ (169,406)	$ 26,378

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES (Continued)

Following is the condensed consolidating statement of cash flows for the year ended December 31, 2015 (in thousands):

	Clean Harbors, Inc.	U.S. Guarantor Subsidiaries	Foreign Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Net cash from operating activities	$ 9,543	$ 314,585	$ 72,255	—	$ 396,383
Cash flows from investing activities:					
Additions to property, plant and equipment	—	(220,789)	(36,407)	—	(257,196)
Proceeds from sales of fixed assets	—	1,447	4,748	—	6,195
Acquisitions, net of cash acquired	—	(94,345)	—	—	(94,345)
Additions to intangible assets including costs to obtain or renew permits	—	—	(5,296)	—	(5,296)
Intercompany	—	(75,506)	—	75,506	—
Intercompany debt	—	14,272	—	(14,272)	—
Net cash used in investing activities	—	(374,921)	(36,955)	61,234	(350,642)
Cash flows from (used in) financing activities:					
Change in uncashed checks	—	(10,129)	(4,501)	—	(14,630)
Proceeds from exercise of stock options	397	—	—	—	397
Remittance of shares, net	(2,159)	—	—	—	(2,159)
Excess tax benefit of stock-based compensation	71	—	—	—	71
Repurchases of common stock	(73,347)	—	—	—	(73,347)
Payments on capital leases	—	(203)	(308)	—	(511)
Intercompany	75,506	—	—	(75,506)	—
Intercompany debt	—	—	(14,272)	14,272	—
Net cash from (used in) financing activities	468	(10,332)	(19,081)	(61,234)	(90,179)
Effect of exchange rate change on cash	—	—	(17,733)	—	(17,733)
Increase (decrease) in cash and cash equivalents	10,011	(70,668)	(1,514)	—	(62,171)
Cash and cash equivalents, beginning of year	1,006	154,147	91,726	—	246,879
Cash and cash equivalents, end of year	$ 11,017	$ 83,479	$ 90,212	—	$ 184,708

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES (Continued)

Following is the condensed consolidating statement of cash flows for the year ended December 31, 2014 (in thousands):

	Clean Harbors, Inc.	U.S. Guarantor Subsidiaries	Foreign Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Net cash from operating activities	$ (5,242)	$ 70,761	$ 250,433	(18,586)	$ 297,366
Cash flows from investing activities:					
Additions to property, plant and equipment	—	(172,525)	(85,088)	—	(257,613)
Proceeds from sales of fixed assets	—	3,956	4,208	—	8,164
Acquisitions, net of cash acquired	—	(6,550)	(9,637)	—	(16,187)
Additions to intangible assets, including costs to obtain or renew permits	—	(623)	(5,896)	—	(6,519)
Intercompany	—	(112,134)	—	112,134	—
Intercompany debt	—	143,467	—	(143,467)	—
Proceeds from sale of long-term investments	—	—	13,861	—	13,861
Net cash used in investing activities	—	(144,409)	(82,552)	(31,333)	(258,294)
Cash flows from (used in) financing activities:					
Change in uncashed checks	—	11,046	4,023	—	15,069
Remittance of shares, net	(2,793)	—	—	—	(2,793)
Repurchases of common stock	(104,341)	—	—	—	(104,341)
Proceeds from employee stock purchase plan	4,364	—	—	—	4,364
Payments on capital leases	—	(170)	(1,952)	—	(2,122)
Repayments of long-term obligations	(5,000)	—	—	—	(5,000)
Excess tax benefit of stock-based compensation	878	—	—	—	878
Dividends paid	—	(18,586)	—	18,586	—
Intercompany	112,134	—	—	(112,134)	—
Intercompany debt	—	—	(143,467)	143,467	—
Net cash from (used in) financing activities	5,242	(7,710)	(141,396)	49,919	(93,945)
Effect of exchange rate change on cash	—	—	(8,321)	—	(8,321)
(Decrease) increase in cash and cash equivalents	—	(81,358)	18,164	—	(63,194)
Cash and cash equivalents, beginning of year	1,006	235,505	73,562	—	310,073
Cash and cash equivalents, end of year	$ 1,006	$ 154,147	$ 91,726	$ —	$ 246,879

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(18) GUARANTOR AND NON-GUARANTOR SUBSIDIARIES (Continued)

Following is the condensed consolidating statement of cash flows for the year ended December 31, 2013 (in thousands):

	Clean Harbors, Inc.	U.S. Guarantor Subsidiaries	Foreign Non-Guarantor Subsidiaries	Consolidating Adjustments	Total
Net cash from operating activities	$ (33,932)	$ 277,445	$ 185,686	(13,360)	$ 415,839
Cash flows from investing activities:					
Additions to property, plant and equipment	—	(145,075)	(135,132)	—	(280,207)
Proceeds from sales of fixed assets and assets held for sale	—	1,078	3,621	—	4,699
Acquisitions, net of cash acquired	(6,025)	(57,239)	—	—	(63,264)
Additions to intangible assets including costs to obtain or renew permits	—	(5,247)	(1,493)	—	(6,740)
Intercompany debt	—	27,525	—	(27,525)	—
Net cash used in investing activities	(6,025)	(178,958)	(133,004)	(27,525)	(345,512)
Cash flows from (used in) financing activities:					
Change in uncashed checks	—	9,922	2,346	—	12,268
Proceeds from employee stock purchase plan	7,425	—	—	—	7,425
Proceeds from exercise of stock options	400	—	—	—	400
Remittance of shares, net	(731)	—	—	—	(731)
Excess tax benefit of stock-based compensation	1,409	—	—	—	1,409
Deferred financing costs paid	(2,504)	—	—	—	(2,504)
Payments of capital leases	—	(227)	(4,664)	—	(4,891)
Issuance costs related to issuance of common stock	(250)	—	—	—	(250)
Dividends paid	—	(13,360)	—	13,360	—
Intercompany debt	—	—	(27,525)	27,525	—
Net cash from (used in) financing activities	5,749	(3,665)	(29,843)	40,885	13,126
Effect of exchange rate change on cash	—	—	(3,216)	—	(3,216)
(Decrease) increase in cash and cash equivalents	(34,208)	94,822	19,623	—	80,237
Cash and cash equivalents, beginning of year	35,214	140,683	53,939	—	229,836
Cash and cash equivalents, end of year	$ 1,006	$ 235,505	$ 73,562	$ —	$ 310,073

CLEAN HARBORS, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(19) QUARTERLY DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(in thousands except per share amounts)			
2015				
Revenues	$ 732,499	$ 936,228	$ 893,366	$ 713,044
Cost of revenues (1)	546,507	652,688	634,646	522,965
Income from operations (4)	7,302	60,758	93,970	25,549
Other income (expense)	409	(660)	(139)	(990)
Net (loss) income	(7,089)	10,395	40,228	568
Basic (loss) earnings per share (2)	(0.12)	0.18	0.69	0.01
Diluted (loss) earnings per share (2)	(0.12)	0.18	0.69	0.01

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter(3)
	(in thousands except per share amounts)			
2014				
Revenues	$ 846,667	$ 858,480	$ 851,465	$ 845,024
Cost of revenues (1)	625,719	606,950	598,407	610,720
Income (loss) from operations (4)	29,906	67,115	(42,748)	57,537
Other income (expense)	4,178	(655)	613	244
Net income (loss)	8,960	28,672	(93,337)	27,377
Basic earnings (loss) per share (2)	0.15	0.47	(1.55)	0.46
Diluted earnings (loss) per share (2)	0.15	0.47	(1.55)	0.46

(1) Items shown separately on the statements of income consist of (i) accretion of environmental liabilities and (ii) depreciation and amortization.

(2) (Loss) earnings per share are computed independently for each of the quarters presented. Accordingly, the quarterly basic and diluted (loss) earnings per share may not equal the total computed for the year.

(3) In the fourth quarter of 2014 an adjustment was recorded to correct income tax expense that was recorded in the third quarter of 2014 resulting in a benefit of approximately $5.4 million in the fourth quarter.

(4) The second quarter of 2015 results include a $32.0 million goodwill impairment charge in our Oil and Gas Field Services reporting unit and the third quarter of 2014 results include a $123.4 million goodwill impairment charge in our Kleen Performance Products reporting unit.

(20) SUBSEQUENT EVENTS

On February 3, 2016, the Company purchased a re-refinery facility located in Nevada from Vertex Energy, Inc. for a purchase price of $35.0 million in cash, subject to customary post-closing adjustments. The acquired re-refinery facility further expands the Company's re-refinery network within its Kleen Performance Products segment.

CLEAN HARBORS, INC. AND SUBSIDIARIES

SCHEDULE II

VALUATION AND QUALIFYING ACCOUNTS

For the Three Years Ended December 31, 2015

(in thousands)

Allowance for Doubtful Accounts	Balance Beginning of Period	Additions Charged to Operating Expense	Deductions from Reserves(a)	Balance End of Period
2013	$ 1,246	$ 7,933	$ 1,825	$ 7,354
2014	$ 7,354	$ 8,917	$ 2,795	$ 13,476
2015	$ 13,476	$ 4,793	$ 3,075	$ 15,194

(a) Amounts deemed uncollectible, net of recoveries.

Revenue Allowance(b)	Balance Beginning of Period	Additions Charged to Revenue	Deductions from Reserves	Balance End of Period
2013	$ 9,879	$ 16,401	$ 15,528	$ 10,752
2014	$ 10,752	$ 20,237	$ 18,804	$ 12,185
2015	$ 12,185	$ 28,312	$ 24,265	$ 16,232

(b) Due to the nature of the Company's business and the invoices that result from the services provided, customers may withhold payments and attempt to renegotiate amounts invoiced. In addition, for some of the services provided, the Company's invoices are based on quotes that can either generate credits or debits when the actual revenue amount is known. Based on industry knowledge and historical trends, the Company records a revenue allowance accordingly. This practice causes the volume of activity flowing through the revenue allowance during the year to be higher than the balance at the end of the year. Increases in overall sales volumes and the expansion of the customer base in recent years have also increased the volume of additions and deductions to the allowance during the year, as well as increased the amount of the allowance at the end of the year. The revenue allowance is intended to cover the net amount of revenue adjustments that may need to be credited to customers' accounts in future periods. Management determines the appropriate total revenue allowance by evaluating the following factors on a customer-by-customer basis as well as on a consolidated level: trends in adjustments to previously billed amounts, existing economic conditions and other information as deemed applicable. Revenue allowance estimates can differ materially from the actual adjustments, but historically the revenue allowance has been sufficient to cover the net amount of the reserve adjustments issued in subsequent reporting periods.

Valuation Allowance on Deferred Tax Assets	Balance Beginning of Period	Additions (Deductions) Charged to (from) Income Tax Expense	Other Changes to Reserves	Balance End of Period
2013	$ 26,325	$ (1,545)	$ 4,946	$ 29,726
2014	$ 29,726	$ (1,812)	$ 1,147	$ 29,061
2015	$ 29,061	$ 2,274	$ (419)	$ 30,916

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Based on an evaluation under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, as of the end of the period covered by this Annual Report on Form 10-K, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined under Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) were effective as of December 31, 2015 to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control Over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting, as that term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and Chief Financial Officer, the Company conducted an evaluation of its internal control over financial reporting based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

The Company's management evaluated the effectiveness of Clean Harbors internal control over financial reporting as of December 31, 2015. Based on their evaluation under the framework in *Internal Control—Integrated Framework (2013)*, the Company's management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2015 based on the criteria in the *Internal Control—Integrated Framework (2013)*.

Deloitte & Touche LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements, has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2015, which is included below in this Item 9A of this annual report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting identified in connection with the evaluation required by paragraph (d) of Exchange Act Rules 13a-15 or 15d-15 that was conducted during the year ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Limitations on the Effectiveness of Controls

The Company's management, including the Chief Executive Officer and Chief Financial Officer, does not expect that the Company's disclosure controls and procedures or the Company's internal control over financial reporting will prevent all errors and all fraud.

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

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

Further, the design of disclosure controls and procedures and internal control over financial reporting must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations of controls and procedures and internal control over financial reporting, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
of Clean Harbors, Inc.
Norwell, Massachusetts

We have audited the internal control over financial reporting of Clean Harbors, Inc. and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2015 of the Company and our report dated February 25, 2016 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

Boston, Massachusetts
February 25, 2016

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

Except for the information set forth below under Item 12 with respect to securities authorized for issuance under the registrant's equity compensation plans, the information called for by Item 10 (Directors, Executive Officers and Corporate Governance), Item 11 (Executive Compensation), Item 12 (Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters), Item 13 (Certain Relationships and Related Transactions, and Director Independence), and Item 14 (Principal Accountant Fees and Services) is incorporated herein by reference to the registrant's definitive proxy statement for its 2016 annual meeting of shareholders, which definitive proxy statement will be filed with the Securities and Exchange Commission by April 30, 2016.

For the purpose of calculating the aggregate market value of the voting stock of the registrant held by non-affiliates as shown on the cover page of this report, it has been assumed that the directors and executive officers of the registrant, as will be set forth in the Company's definitive proxy statement for its 2016 annual meeting of shareholders, are the only affiliates of the registrant. However, this should not be deemed to constitute an admission that all of such persons are, in fact, affiliates or that there are not other persons who may be deemed affiliates of the registrant.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

In addition to the information about the security ownership of certain beneficial owners and management and related stockholder matters which is incorporated herein by reference to the Company's definitive proxy statement for the Company's 2016 annual meeting of shareholders, the following table includes information as of December 31, 2015 regarding shares of common stock authorized for issuance under the Company's equity compensation plans. The Company's shareholders previously approved each of the plans.

Plan Category	Number of securities to be issued upon exercise of outstanding options and rights(a)	Weighted average exercise price of outstanding options and rights(b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(c)
Equity compensation plans approved by security holders(1)	24,000	$ 28.05	4,986,477

(1) Includes: (i) the Company's 2000 Stock Incentive Plan which expired in 2010, but under which there were on December 31, 2015 outstanding options for an aggregate of 24,000 shares; and (ii) the Company's 2010 Stock Incentive Plan (the "2010 Plan") under which there were on December 31, 2015 no outstanding options but 4,986,477 shares were available for grant of future options, stock appreciation rights, restricted stock awards, restricted stock units and certain other forms of equity incentives. See Note 15, "Stock-Based Compensation and Employee Benefit Plans," to the Company's consolidated financial statements included in Item 8, "Financial Statements and Supplementary Data," in this report.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as a Part of this Report

	Page
1. Financial Statements:	
Report of Independent Registered Public Accounting Firm	51
Consolidated Balance Sheets as of December 31, 2015 and 2014	52
Consolidated Statements of Income (Loss) for the Three Years Ended December 31, 2015	53
Consolidated Statements of Comprehensive (Loss) Income for the Three Years Ended December 31, 2015	54
Consolidated Statements of Cash Flows for the Three Years Ended December 31, 2015	55
Consolidated Statements of Stockholders' Equity for the Three Years Ended December 31, 2015	56
Notes to Consolidated Financial Statements	57
2. Financial Statement Schedule:	
Schedule II Valuation and Qualifying Accounts for the Three Years Ended December 31, 2015	102

All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or notes thereto.

3. Exhibits:

The list of exhibits filed as part of this annual report on Form 10-K is set forth on the Exhibit Index immediately following the signature page to this report, and such Exhibit Index is incorporated herein by reference.

Exhibits to this annual report on Form 10-K have been included only with the copies of the Form 10-K filed with the Securities and Exchange Commission. Upon request to the Company and payment of a reasonable fee, copies of the individual exhibits will be furnished. The Company undertakes to furnish to the Commission upon request copies of instruments (in addition to the exhibits listed below) relating to the Company's acquisitions and long-term debt.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized on February 25, 2016.

CLEAN HARBORS, INC.
By: /s/ ALAN S. MCKIM
Alan S. McKim
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this annual report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ ALAN S. MCKIM Alan S. McKim	Chairman of the Board of Directors and Chief Executive Officer	February 25, 2016
/s/ MICHAEL L. BATTLES Michael L. Battles	Executive Vice President and Chief Financial Officer	February 25, 2016
/s/ ERIC J. DUGAS Eric J. Dugas	Vice President, Corporate Controller and Chief Accounting Officer	February 25, 2016
* James M. Rutledge	Vice Chairman of the Board of Directors and President	February 25, 2016
* Gene Banucci	Director	February 25, 2016
* John P. DeVillars	Director	February 25, 2016
* Edward G. Galante	Director	February 25, 2016
* Rod Marlin	Director	February 25, 2016
* Daniel J. McCarthy	Director	February 25, 2016
* John T. Preston	Director	February 25, 2016
* Andrea Robertson	Director	February 25, 2016
* Thomas J. Shields	Director	February 25, 2016
* John R. Welch	Director	February 25, 2016

*By: /s/ ALAN S. MCKIM
Alan S. McKim
Attorney-in-Fact

EXHIBIT INDEX

Item No.	Description	Location
2.1	Acquisition Agreement by and between Safety-Kleen Services, Inc., as Seller, and Clean Harbors, Inc., as Purchaser, dated as of February 22, 2002	(1)
2.2	First Amendment to Acquisition Agreement by and between Safety-Kleen Services, Inc., as Seller, and Clean Harbors, Inc., as Purchaser, dated as of March 8, 2002	(2)
2.3	Second Amendment to Acquisition Agreement by and between Safety-Kleen Services, Inc. as Seller, and Clean Harbors, Inc. as Purchaser, dated as of April 30, 2002	(3)
2.4	Third Amendment to Acquisition Agreement by and between Safety-Kleen Services, Inc., as Seller, and Clean Harbors, Inc., as Purchaser, dated as of September 6, 2002	(4)
2.5	Fourth Amendment to Acquisition Agreement by and between Safety-Kleen Services, Inc., as Seller and Clean Harbors, Inc., as Purchaser, dated as of July 14, 2003	(5)
2.6	Agreement and Plan of Merger dated as of October 26, 2012 among Safety-Kleen, Inc., Clean Harbors, Inc., and CH Merger Sub, Inc.	(6)
3.1A	Restated Articles of Organization of Clean Harbors, Inc.	(7)
3.1B	Articles of Amendment [as filed on May 9, 2011] to Restated Articles of Organization of Clean Harbors	(8)
3.4D	Amended and Restated By-Laws of Clean Harbors, Inc.	(9)
4.33E-1	Fourth Amended and Restated Credit Agreement dated as of January 17, 2013 among Clean Harbors, Inc., as the U.S. Borrower, Clean Harbors Industrial Services Canada, Inc., as the Canadian Borrower, Bank of America, N.A., as Administrative Agent, and the Lenders party thereto	(10)
4.33F	Guarantee (U.S. Domiciled Loan Parties-U.S. Facility Obligations) dated as of May 31, 2011 executed by the U.S. Domiciled Subsidiaries of Clean Harbors, Inc. named therein in favor of Bank of America, N.A., as Agent for itself and the other U.S. Facility Secured Parties	(11)
4.33G	Guarantee (Canadian Domiciled Loan Parties-Canadian Facility Obligations) dated as of May 31, 2011 executed by the Canadian Domiciled Subsidiaries of Clean Harbors, Inc. named therein in favor of Bank of America, N.A., as Agent for itself and the other Canadian Facility Secured Parties	(11)
4.33H	Guarantee (U.S. Domiciled Loan Parties-Canadian Facility Obligations) dated as of May 31, 2011 executed by Clean Harbors, Inc. and the U.S. Domiciled Subsidiaries of Clean Harbors, Inc. named therein in favor of Bank of America, N.A., as Agent for itself and the other Canadian Facility Secured Parties	(11)
4.33I	Security Agreement (U.S. Domiciled Loan Parties) dated as of January 17, 2013 among Clean Harbors, Inc. , as the U.S. Borrower and a Grantor, the subsidiaries of Clean Harbors, Inc. listed on Annex A thereto or that thereafter become a party thereto as Grantors, and Bank of America, N.A., as Agent	(10)
4.33J	Security Agreement (Canadian Domiciled Loan Parties) dated as of May 31, 2011 among Clean Harbors Industrial Services Canada, Inc., as the Canadian Borrower and a Grantor, the Canadian subsidiaries of Clean Harbors, Inc. listed on Annex A thereto or that thereafter become a party thereto as Grantors, and Bank of America, N.A., as Agent	(11)
4.40	Indenture dated as of July 30, 2012, among Clean Harbors, Inc., as Issuer, the Guarantors listed on the signature pages thereto, and U.S. Bank National Association, as Trustee	(12)
4.42	Indenture dated as of December 7, 2012, among Clean Harbors, Inc., as Issuer, the subsidiaries of Clean Harbors, Inc. named therein as Guarantors, and U.S. Bank National Association, as Trustee	(13)
10.43*	Key Employee Retention Plan	(14)
10.43A*	Form of Severance Agreement under Key Employee Retention Plan with Confidentiality and Non-Competition Agreement	(15)
10.45	Bill of Sale and Assignment dated as of September 10, 2002 by Safety-Kleen Services, Inc. and its Subsidiaries named therein, as Sellers, and Clean Harbors, Inc., as Purchaser, and its Subsidiaries named therein, as Purchasing Subs	(4)
10.46	Assumption Agreement made as of September 10, 2002 by Clean Harbors, Inc. in favor of Safety-Kleen Services, Inc. and its Subsidiaries named therein	(4)
10.50*	Accepted offer letter, severance agreement, and relocation package and agreement, effective August 1, 2005, between the Company and James M. Rutledge	(16)

Item No.	Description	Location
10.52B*	Clean Harbors, Inc. Management Incentive Plan [as amended and restated on March 5, 2012]	(17)
10.53*	Clean Harbors, Inc. Annual CEO Incentive Bonus Plan	(18)
10.54*	Clean Harbors, Inc. 2010 Stock Incentive Plan [as amended on May 10, 2010]	(19)
10.54A*	Revised form of Restricted Stock Award Agreement [Non-Employee Director] [for use under 2010 Stock Incentive Plan]	(15)
10.54B*	Revised form of Restricted Stock Award Agreement [Employee] [for use under Clean Harbors, Inc. 2010 Stock Incentive Plan]	(15)
10.54C*	Revised form of Performance-Based Restricted Stock Award Agreement [for use under Clean Harbors, Inc. 2010 Stock Incentive Plan]	(15)
10.54D*	Amendment to Section 8 and 10(i) of the Company's 2010 Stock Incentive Plan	(20)
10.55*	Clean Harbors, Inc. 2014 CEO Annual Incentive Plan	(21)
10.55A*	Amendment to Section 6(m) of Clean Harbors, Inc. 2014 Annual CEO Incentive Plan	(22)
10.56*	Mike Battles accepted offer letter effective as of January 6, 2016	(23)
21	Subsidiaries	Filed herewith
23	Consent of Independent Registered Public Accounting Firm	Filed herewith
24	Power of Attorney	Filed herewith
31.1	Rule 13a-14a/15d-14(a) Certification of the CEO Alan S. McKim	Filed herewith
31.2	Rule 13a-14a/15d-14(a) Certification of the CFO Michael L. Battles	Filed herewith
32	Section 1350 Certifications	Filed herewith
101	The following materials from the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015, formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Income, (iii) Consolidated Statements of Comprehensive Income, (iv) Consolidated Statements of Cash Flows, (v) Consolidated Statements of Stockholders' Equity, and (vi) Notes to Consolidated Financial Statements, tagged as blocks of text	(24)

(*) A "management contract or compensatory plan or arrangement" filed as an exhibit to this report pursuant to Item 15(f) of Form 10-K.

(1) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on February 28, 2002.

(2) Incorporated by reference to the similarly numbered exhibit to the Company's Form 10-K Annual Report for the Year ended December 31, 2001.

(3) Incorporated by reference to the similarly numbered exhibit to the Company's Form 10-Q Quarterly Report for the Quarterly Period ended March 31, 2002.

(4) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on September 25, 2002.

(5) Incorporated by reference to the similarly numbered exhibit to the Company's Form 10-Q Quarterly Report for the Quarterly Period ended June 30, 2003.

(6) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on October 31, 2012.

(7) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on May 19, 2005.

(8) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on May 12, 2011.

(9) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on December 22, 2014.

(10) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on January 18, 2013.

(11) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on June 3, 2011.

(12) Incorporated by reference to the similarly numbered exhibit to the Company's Report on Form 8-K filed on July 30, 2012.

(13) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on December 10, 2012.

(14) Incorporated by reference to the similarly numbered exhibit to the Company's Form 10-Q Quarterly Report for the Quarterly Period ended March 31, 1999.

(15) Incorporated by reference to the similarly numbered exhibit to the Company's Form 10-K Annual Report for the Year ended December 31, 2010.

(16) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on August 1, 2005.

(17) Incorporated by reference to Appendix A to the Company's definitive proxy statement for its 2012 annual meeting of shareholders filed on March 23, 2012.

(18) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on May 14, 2009.

(19) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on May 14, 2010.

(20) Incorporated by reference to Appendix B to the Company’s definitive Proxy Statement filed on March 22, 2013.

(21) Incorporated by reference by Appendix A to the Company’s definitive Proxy Statement filed on March 22, 2013.

(22) Incorporated by reference to Appendix A to the Company's definitive Proxy Statement for its 2014 annual meeting of shareholders filed on April 29, 2014.

(23) Incorporated by reference to the similarly numbered exhibit to the Company's Form 8-K Report filed on January 11, 2016.

(24) These interactive data files are furnished herewith and deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.

Exhibit 21

Subsidiaries of Clean Harbors, Inc.

Subsidiary	Jurisdiction of Organization
510127 NB Inc.*	New Brunswick
677244 NB Inc.*	New Brunswick
Altair Disposal Services, LLC	Delaware
ARC Advanced Reactors and Columns, LLC	Delaware
Baton Rouge Disposal, LLC	Delaware
BCT Structures, ULC*	Alberta
Bridgeport Disposal, LLC	Delaware
Cat Tech International, Ltd.*	Bahamas
CH Canada GP, Inc.*	Ontario
CH Canada Holdings Corp.*	Nova Scotia
CH International Holdings, LLC	Delaware
Clean Harbors (Mexico), Inc.	Delaware
Clean Harbors Andover, LLC	Delaware
Clean Harbors Antioch, LLC	Delaware
Clean Harbors Aragonite, LLC	Delaware
Clean Harbors Arizona, LLC	Delaware
Clean Harbors Baton Rouge, LLC	Delaware
Clean Harbors BDT, LLC	Delaware
Clean Harbors Buttonwillow, LLC	Delaware
Clean Harbors Canada LP*	Ontario
Clean Harbors Canada, Inc.*	New Brunswick
Clean Harbors Caribe, Inc.*	Puerto Rico
Clean Harbors Catalyst Services Trinidad Limited*	Trinidad
Clean Harbors Catalyst Services, LLC	Delaware
Clean Harbors Catalyst Services LP*	Alberta
Clean Harbors Catalyst Services Ltd.*	Nova Scotia
Clean Harbors Chattanooga, LLC	Delaware
Clean Harbors Clive, LLC	Delaware
Clean Harbors Coffeyville, LLC	Delaware
Clean Harbors Colfax, LLC	Delaware
Clean Harbors Deer Park, LLC	Delaware
Clean Harbors Deer Trail, LLC	Delaware
Clean Harbors Development, LLC	Delaware
Clean Harbors Directional Boring Services, ULC*	Alberta
Clean Harbors Directional Boring Services LP*	Alberta
Clean Harbors Disposal Services, Inc.	Delaware
Clean Harbors El Dorado, LLC	Delaware
Clean Harbors Energy and Industrial Services Corp.*	Alberta
Clean Harbors Energy and Industrial Services LP*	Alberta
Clean Harbors Energy and Industrial Western Ltd.*	Alberta
Clean Harbors Energy Services ULC*	Alberta

Clean Harbors Environmental Services, Inc.	Massachusetts
Clean Harbors Exploration Services, Inc.	Nevada
Clean Harbors Exploration Services, ULC*	Alberta
Clean Harbors Exploration Services LP*	Alberta
Clean Harbors Florida, LLC	Delaware
Clean Harbors Grassy Mountain, LLC	Delaware
Clean Harbors Industrial Services Canada, Inc.*	Alberta
Clean Harbors Industrial Services, Inc.	Delaware
Clean Harbors Kansas, LLC	Delaware
Clean Harbors Kingston Facility Corporation	Massachusetts
Clean Harbors LaPorte, LLC	Delaware
Clean Harbors Laurel, LLC	Delaware
Clean Harbors Lodging Services LP*	Alberta
Clean Harbors Lodging Services, ULC*	Alberta
Clean Harbors Lone Mountain, LLC	Delaware
Clean Harbors Lone Star Corp.	Delaware
Clean Harbors Los Angeles, LLC	Delaware
Clean Harbors Mercier, Inc.	Quebec
Clean Harbors of Baltimore, Inc.	Delaware
Clean Harbors of Braintree, Inc.	Massachusetts
Clean Harbors of Connecticut, Inc.	Delaware
Clean Harbors Pecatonica, LLC	Delaware
Clean Harbors PPM, LLC	Delaware
Clean Harbors Production Services, ULC*	Alberta
Clean Harbors Quebec, Inc.*	Quebec
Clean Harbors Recycling Services of Chicago, LLC	Delaware
Clean Harbors Recycling Services of Ohio LLC	Delaware
Clean Harbors Reidsville, LLC	Delaware
Clean Harbors San Jose, LLC	Delaware
Clean Harbors San Leon, Inc.	Delaware
Clean Harbors Services, Inc.	Massachusetts
Clean Harbors Surface Rentals, ULC*	Alberta
Clean Harbors Surface Rentals Partnership*	Alberta
Clean Harbors Surface Rentals USA, Inc.	Delaware
Clean Harbors Tennessee, LLC	Delaware
Clean Harbors Westmorland, LLC	Delaware
Clean Harbors White Castle, LLC	Delaware
Clean Harbors Wilmington, LLC	Delaware
Crowley Disposal, LLC	Delaware
CTVI Inc.*	Virgin Islands
Disposal Properties, LLC	Delaware
Environnement Services Et Machinerie E.S.M. Inc.*	Quebec
EnviroSORT Inc.	Alberta

Grizzco Camp Services, ULC*	British Columbia
GSX Disposal, LLC	Delaware
Heckmann Environmental Services, Inc.	Delaware
Hilliard Disposal, LLC	Delaware
JL Filtration Inc.*	Alberta
JL Filtration Operating Limited Partnership*	Alberta
Laidlaw Environmental Services de Mexico S.A. de C.V.*	Mexico
Murphy's Waste Oil Service, Inc.	Massachusetts
Plaquemine Remediation Services, LLC	Delaware
Roebuck Disposal, LLC	Delaware
Safety-Kleen de Mexico, S. de R.L. de C.V.*	Mexico
Safety-Kleen Canada Inc.*	New Brunswick
Safety-Kleen Envirosystems Company	California
Safety-Kleen Envirosystems Company of Puerto Rico, Inc.	Indiana
Safety-Kleen, Inc.	Delaware
Safety-Kleen International, Inc.	Delaware
Safety-Kleen International Asia Investment Company Limited*	Hong Kong
Safety-Kleen of California, Inc.	California
Safety-Kleen Systems, Inc.	Wisconsin
Sanitherm, ULC*	Alberta
Sanitherm USA, Inc.	Delaware
Sawyer Disposal Services, LLC	Delaware
Service Chemical, LLC	Delaware
SK Holding Company, Inc.	Delaware
SK D'Incineration Inc.*	Quebec
SK Servicios Ambientales Administrativos, S. de R.L. de C.V.*	Mexico
Spring Grove Resource Recovery, Inc.	Delaware
The Solvents Recovery Service of New Jersey, Inc.	New Jersey
Thermo Fluids Inc.	Delaware
Tri-vax Enterprises Ltd.*	Alberta
Tulsa Disposal, LLC	Delaware
Versant Energy Services, Inc.	Delaware
Versant Energy Services, LP*	Alberta

*Foreign entity or subsidiary of foreign entity

EXHIBIT 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-63662, 333-134381, and 333-166963 on Form S-8 and No. 333-185141 on Form S-3 of our reports dated February 25, 2016, relating to the consolidated financial statements and financial statement schedule of Clean Harbors, Inc. (the "Company"), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Clean Harbors, Inc. for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Boston, Massachusetts
February 25, 2016

EXHIBIT 24

POWER OF ATTORNEY

Know all by these presents, that the undersigned hereby constitutes and appoints each of Alan S. McKim and Michael L. Battles, signing singly, the undersigned's true and lawful attorney-in-fact to:

(1) execute for and on behalf of the undersigned, in the undersigned's capacity as an officer and/or director of Clean Harbors, Inc. (the "Company"), any and all documents required by the Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934 and the rules thereunder, including, without limitation, Form 10-K;

(2) do and perform any and all acts for and on behalf of the undersigned which may be necessary or desirable to complete and execute any such document filing and timely file such form with the United States Securities and Exchange Commission and any stock exchange or similar authority; and

(3) take any other action of any type whatsoever in connection with the foregoing which, in the opinion of such attorney-in-fact, may be of benefit to, and in the best interest of, or legally required by, the undersigned.

The undersigned hereby grants to each such attorney-in-fact full power and authority to do and perform any and every act and thing whatsoever requisite, necessary, or proper to be done in the exercise of any of the rights and powers herein granted, as fully to all intents and purposes as the undersigned might or could do if personally present, with full power of substitution or revocation, hereby ratifying and confirming all that such attorney-in-fact, or such attorney-in-fact's substitute or substitutes, shall lawfully do or cause to be done by virtue of this power of attorney and the rights and powers herein granted. The undersigned acknowledges that the foregoing attorneys-in-fact, in serving in such capacity at the request of the undersigned, are not assuming, nor is the Company assuming, any of the undersigned's responsibilities to comply with Section 16 of the Securities Exchange Act of 1934.

This Power of Attorney shall remain in full force and effect until the undersigned is no longer required with respect to the undersigned's capacity as an officer and/or director and/or holdings of and transactions in securities issued by the Company, unless earlier revoked by the undersigned in a signed writing delivered to the foregoing attorneys-in-fact.

IN WITNESS WHEREOF, the undersigned has caused this Power of Attorney to be executed as of this 25th day of February, 2016.

Signature

/s/ JAMES M. RUTLEDGE

/s/ GENE BANUCCI

/s/ JOHN P. DEVILLARS

/s/ EDWARD G. GALANTE

/s/ ROD MARLIN

/s/ DANIEL J. MCCARTHY

/s/ JOHN T. PRESTON

/s/ ANDREA ROBERTSON

/s/ THOMAS J. SHIELDS

/s/ JOHN R. WELCH

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER

I, Alan S. McKim, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2015 of Clean Harbors, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Alan S. McKim

Alan S. McKim

Chief Executive Officer

Date: February 25, 2016

Exhibit 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER

I, Michael L. Battles, certify that:

1. I have reviewed this annual report on Form 10-K for the period ended December 31, 2015 of Clean Harbors, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ Michael L. Battles

Michael L. Battles

Executive Vice President and Chief Financial Officer

Date: February 25, 2016

EXHIBIT 32

CLEAN HARBORS, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO
SECTION 1350, CHAPTER 63 OF TITLE 18, UNITED STATES CODE,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES OXLEY ACT OF 2002

Pursuant to 18 U.S.C. §1350, each of the undersigned certifies that, to his knowledge, this Annual Report on Form 10-K for the year ended December 31, 2015 fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in this report fairly presents, in all material respects, the financial condition and results of operations of Clean Harbors, Inc.

Date: February 25, 2016

By: /s/ ALAN S. MCKIM
Alan S. McKim
Chief Executive Officer

Date: February 25, 2016

By: /s/ MICHAEL L. BATTLES
Michael L. Battles
Executive Vice President and Chief Financial Officer

ATTACHMENT C

SEC FORM 10-K FOR ENTERPRISE PRODUCTS PARTNERS L.P.

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

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2015

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from ___ to ___.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as Specified in Its Charter)

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

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

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

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

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

Securities to be registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

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

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

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

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

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

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the partnership's common units held by non-affiliates at June 30, 2015 (the last business day of the registrant's most recently completed second fiscal quarter) was $39.27 billion based on a closing price on that date of $29.89 per common unit on the New York Stock Exchange Composite ticker tape. There were 2,021,263,324 common units outstanding at January 31, 2016.

ENTERPRISE PRODUCTS PARTNERS L.P.
TABLE OF CONTENTS

		Page Number
	PART I	
Item 1 and 2.	Business and Properties.	2
Item 1A.	Risk Factors.	38
Item 1B.	Unresolved SEC Staff Comments.	57
Item 3.	Legal Proceedings.	57
Item 4.	Mine Safety Disclosures.	58
	PART II	
Item 5.	Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.	59
Item 6.	Selected Financial Data.	61
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations.	63
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk.	104
Item 8.	Financial Statements and Supplementary Data.	107
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.	107
Item 9A.	Controls and Procedures.	108
Item 9B.	Other Information.	111
	PART III	
Item 10.	Directors, Executive Officers and Partnership Governance.	111
Item 11.	Executive Compensation.	121
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.	130
Item 13.	Certain Relationships and Related Transactions, and Director Independence.	133
Item 14.	Principal Accountant Fees and Services.	136
	PART IV	
Item 15.	Exhibits and Financial Statement Schedules.	137
Signatures		147

KEY REFERENCES USED IN THIS REPORT

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

The membership interests of Dan Duncan LLC are owned by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director and Chairman of the Board of 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. 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 President 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 Administrative Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 33.6% of our limited partner interests at December 31, 2015.

References to "Oiltanking" and "Oiltanking GP" mean Oiltanking Partners, L.P. and OTLP GP, LLC, the general partner of Oiltanking, respectively. In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking, all of the member interests of Oiltanking GP and the incentive distribution rights held by Oiltanking GP from Oiltanking Holding Americas, Inc. 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.

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company ("Pioneer") and Reliance Industries Limited ("Reliance").

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, 2015 (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," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking

statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Part I, Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

PART I

Item 1 and 2. *Business and Properties.*

General

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 midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; petrochemical and refined products transportation, storage and terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets currently include approximately 49,000 miles of pipelines; 250 MMBbls of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 Bcf of natural gas storage capacity.

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

Like many publicly traded partnerships, we have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to an administrative services agreement (the "ASA") or by other service providers. As of February 1, 2016, there were approximately 6,800 EPCO personnel who spend all or a substantial portion of their time engaged in our business. For additional information regarding the ASA, see "EPCO ASA" under Note 15 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Business Strategy

Our integrated midstream energy asset network links producers of natural gas, NGLs and crude oil from some of the largest supply basins in the United States ("U.S."), Canada and Gulf of Mexico with domestic consumers and international markets. Our business strategy seeks to leverage this network to:

- capitalize on expected demand growth, including exports, for natural gas, NGLs, crude oil and petrochemical and refined products;
- maintain a diversified portfolio of midstream energy assets and expand this asset base through growth capital projects and accretive acquisitions of complementary midstream energy assets;
- enhance the stability of our cash flows by investing in pipelines and other fee-based businesses; and
- share capital costs and risks through joint ventures or alliances with strategic partners, including those that provide processing, throughput or feedstock volumes for growth capital projects or purchase such projects' end products.

Commercial and Liquidity Outlook for 2016

For information regarding our commercial and liquidity outlook for the year ending December 31, 2016, see "General Outlook for 2016" included under Part II, Item 7 of this annual report.

Major Customer Information

Substantially all of our consolidated revenues are earned in the U.S. and derived from a wide customer base. Our largest non-affiliated customer for 2015 was Shell Oil Company and its affiliates (collectively, "Shell"), which accounted for 7.4% of our consolidated revenues. See Note 10 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for additional information regarding our largest non-affiliated customers for the years ended December 31, 2015, 2014 and 2013.

Business Segments

General

The following sections provide an overview of our business segments, including information regarding principal products produced and/or services rendered and properties owned. Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & 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.

On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015.

Each of our remaining 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.

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. Such financial information is incorporated by reference into this Part I, Item 1 and 2 discussion.

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, and the cost and availability of capital to energy companies to invest in upstream exploration and production activities. For information regarding such risks, see Part I, Item 1A of this annual report. In addition, our business activities are subject to various federal, state and local laws and regulations governing a wide variety of topics, including commercial, operational, environmental, safety and other matters. For a discussion of the principal effects of such laws and regulations on our business activities, see "Regulatory Matters" within this Part I, Item 1 and 2 discussion.

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

NGL Pipelines & Services

Our NGL Pipelines & Services business segment includes our natural gas processing plants and related NGL marketing activities; approximately 19,500 miles of NGL pipelines; NGL and related product storage facilities; and 15 NGL fractionators. This segment also includes our NGL export docks and related operations.

Natural gas processing plants and related NGL marketing activities

At the core of our natural gas processing business are 24 processing plants located in Colorado, Louisiana, Mississippi, New Mexico, Texas and Wyoming. In its raw form, natural gas produced at the wellhead (especially in association with crude oil) contains varying amounts of mixed NGLs. Natural gas streams containing NGLs are usually not acceptable for transportation in natural gas pipelines or for commercial use as a fuel; therefore, the streams must be transported to a natural gas processing plant to remove the NGLs and impurities. Once the natural gas is processed and NGLs and impurities are removed, the natural gas meets pipeline and commercial quality specifications. On an energy-equivalent basis, most NGLs generally have greater economic value as feedstock for petrochemical and motor gasoline production than as components of a natural gas stream.

In our natural gas processing business, our 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. 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, 2015, we estimate that the terms of approximately 45.4% of our current portfolio of natural gas processing contracts (based on natural gas inlet volumes) were entirely fee-based, with an additional 23.1% of this portfolio including a combination of fee-based and commodity-based terms. The terms of the remaining 31.5% of our portfolio of natural gas processing contracts were entirely commodity-based.

Our commodity-based contracts include keepwhole and margin-band contracts, percent-of-liquids contracts, percent-of-proceeds contracts and contracts featuring a combination of commodity and fee-based terms, as described further below:

- Under keepwhole and margin-band contracts, we take ownership of mixed NGLs extracted from the producer's natural gas stream while replacing the equivalent quantity of energy on a natural gas basis to producers. We recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts.

- Under percent-of-liquids contracts, we take ownership of a portion of the mixed NGLs extracted from the producer's natural gas stream (in lieu of a cash processing fee) and recognize revenue when the extracted NGLs are delivered and sold to customers under NGL marketing sales contracts.

- Under percent-of-proceeds contracts, we share in the proceeds generated from the sale of mixed NGLs we extract on the producer's behalf (in lieu of a cash processing fee).

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

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

If the operating 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.

Once mixed NGLs are extracted by a natural gas processing plant, the products are typically transported to a centralized fractionation facility for separation into purity NGL products (ethane, propane, normal butane, isobutane and natural gasoline). Purity NGL products are used as feedstocks by the petrochemical industry, as feedstocks by refineries in the production of motor gasoline and as fuel by industrial and residential consumers, as follows:

- 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.

Our NGL marketing activities generate revenues from merchant activities such as term and spot sales of NGLs, which we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and contract purchases. The results of operations 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 NGL product quality. Market prices for NGLs are subject to fluctuations in response to changes in supply and demand and a variety of additional factors that are beyond our control. 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 1,080 railcars, the majority of which are leased from third parties. These railcars are used to deliver feedstocks to our facilities and to distribute NGLs throughout the U.S. and parts of Canada. We have rail loading and unloading capabilities at certain of our terminal facilities in Arizona, California, Kansas, Louisiana, Minnesota, Mississippi, Nevada, New York, North Carolina and Texas. These facilities service both our rail shipments and those of our customers.

Our NGL marketing activities also utilize a fleet of approximately 90 tractor-trailer tank trucks, the majority of which we lease and operate, that are used to transport LPG for us and on behalf of third parties.

The following table presents selected information regarding our natural gas processing facilities at February 1, 2016:

Description of Asset	Location(s)	Our Ownership Interest	Net Gas Processing Capacity (Bcf/d) (1)	Total Gas Processing Capacity (Bcf/d)
Natural gas processing facilities:				
Meeker	Colorado	100.0%	1.80	1.80
Pioneer (two facilities)	Wyoming	100.0%	1.35	1.35
Yoakum	Texas	100.0%	1.05	1.05
North Terrebonne	Louisiana	61.9% (2)	0.66	0.95
Chaco	New Mexico	100.0%	0.60	0.60
Neptune	Louisiana	66.0% (2)	0.43	0.65
Pascagoula	Mississippi	40.0% (2)	0.40	1.50
Sea Robin	Louisiana	50.6% (2)	0.33	0.65
Thompsonville	Texas	100.0%	0.33	0.33
Shoup	Texas	100.0%	0.28	0.28
Gilmore	Texas	100.0%	0.25	0.25
Armstrong	Texas	100.0%	0.25	0.25
Toca	Louisiana	73.2% (2)	0.22	0.30
San Martin	Texas	100.0%	0.20	0.20
Indian Basin	New Mexico	42.4% (2)	0.18	0.18
Delmita	Texas	100.0%	0.15	0.15
Carlsbad	New Mexico	100.0%	0.13	0.13
Sonora	Texas	100.0%	0.12	0.12
Shilling	Texas	100.0%	0.11	0.11
Venice	Louisiana	13.1% (3)	0.10	0.75
Indian Springs	Texas	75.0% (2)	0.09	0.12
Burns Point	Louisiana	50.0% (2)	0.08	0.16
Chaparral	New Mexico	100.0%	0.04	0.04
Total			9.15	11.92

(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) Our ownership in the Venice plant is held indirectly through our equity method investment in Venice Energy Services Company, L.L.C. ("VESCO").

We operate all of our natural gas processing facilities except for the Pascagoula, Indian Basin and Venice plants. On a weighted-average basis, utilization rates for our natural gas processing plants were 56.7%, 59.1% and 54.1% during the years ended December 31, 2015, 2014 and 2013, respectively.

Delaware Basin plant
In April 2015, we formed a joint venture with an affiliate of Occidental Petroleum Corporation to develop a new 150 MMcf/d cryogenic natural gas processing facility that will accommodate growing production of NGL-rich natural gas from the Delaware Basin, a prolific production area in West Texas and southern New Mexico. The facility is supported by long-term, firm contracts and is expected to begin operations in mid-2016. We serve as construction manager for the project and will serve as operator once the new facility commences operations. The new facility is located in Reeves County, Texas.

South Eddy plant
In September 2014, we announced plans to construct a new cryogenic natural gas processing plant in Eddy County, New Mexico and associated natural gas and NGL pipeline infrastructure to facilitate growing production of NGL-rich natural gas in the Delaware Basin. These assets are expected to begin operations in the second quarter of 2016. The South Eddy natural gas processing plant is expected to have an initial capacity of 200 MMcf/d of natural gas, with the potential for future expansions. Upon completion, this will bring our total natural gas processing plant capacity in the Delaware Basin to approximately 600 MMcf/d.

To supply the new South Eddy plant, we plan to construct approximately 80 miles of natural gas gathering pipelines to complement our existing 1,500 miles of natural gas gathering pipelines located in the Delaware Basin. We also expect to build a 71-mile, 12-inch diameter NGL pipeline to transport NGLs from the South Eddy plant to our Hobbs NGL fractionation and storage facility located in Gaines County, Texas. As a result of multiple pipeline connections at our Hobbs facility, shippers will have access to our NGL fractionation and storage complex at Mont Belvieu, Texas. Additionally, we plan to deliver residue gas from the South Eddy plant through new interconnections with existing third party pipelines located in the vicinity of the plant.

NGL pipelines

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

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

Excluding inventories owned in connection with our marketing activities, we typically do not take title to the products transported by our NGL pipelines; rather, the shipper retains title and the associated commodity price risk.

The following table presents selected information regarding our NGL pipelines at February 1, 2016:

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)
NGL pipelines:			
Mid-America Pipeline System (1)	Midwest and Western U.S.	100.0%	8,074
South Texas NGL Pipeline System	Texas	100.0%	1,918
Dixie Pipeline (1)	South and Southeastern U.S.	100.0%	1,306
Seminole Pipeline (1)	Texas	100.0%	1,248
ATEX (1)	Texas to Midwest and Northeast U.S.	100.0%	1,206
Chaparral NGL System (1)	Texas, New Mexico	100.0%	1,002
Louisiana Pipeline System (1)	Louisiana	100.0%	954
Texas Express Pipeline (1)	Texas	35.0% (2)	593
Skelly-Belvieu Pipeline (1)	Texas, Oklahoma	50.0% (3)	572
Front Range Pipeline (1)	Colorado, Oklahoma, Texas	33.3% (4)	447
Promix NGL Gathering System	Louisiana	50.0% (5)	358
Houston Ship Channel Pipeline System	Texas	100.0%	274
Aegis Ethane Pipeline (1)	Texas, Louisiana	100.0%	270
Rio Grande Pipeline (1)	Texas	70.0% (6)	249
Panola Pipeline (1)	Texas	55.0% (7)	248
Lou-Tex NGL Pipeline (1)	Texas, Louisiana	100.0%	206
Tri-States NGL Pipeline (1)	Alabama, Mississippi, Louisiana	83.3% (8)	167
Texas Express Gathering System	Texas, Oklahoma	45.0% (9)	116
Others (six systems) (10)	Various	Various (11)	311
Total			19,519

(1) Interstate and/or intrastate transportation services provided by these liquids pipelines, in whole or part, are regulated by governmental agencies.
(2) Our ownership interest in the Texas Express Pipeline is held indirectly through our equity method investment in Texas Express Pipeline LLC.
(3) Our ownership interest in the Skelly-Belvieu Pipeline is held indirectly through our equity method investment in Skelly-Belvieu Pipeline Company, L.L.C.
(4) Our ownership interest in the Front Range Pipeline is held indirectly through our equity method investment in Front Range Pipeline LLC.
(5) Our ownership interest in the Promix NGL Gathering System is held indirectly through our equity method investment in K/D/S Promix, L.L.C. ("Promix").
(6) We own a 70% consolidated interest in the Rio Grande Pipeline through our majority owned subsidiary, Rio Grande Pipeline Company.
(7) In January 2015, we formed a joint venture and assigned a 45% interest in Panola Pipeline Company, LLC ("Panola") to third parties. Prior to January 2015, Panola was a wholly owned subsidiary of ours.
(8) We own an 83.3% consolidated interest in the Tri-States NGL Pipeline through our majority owned subsidiary, Tri-States NGL Pipeline, L.L.C.
(9) Our ownership interest in the Texas Express Gathering System is held indirectly through our equity method investment in Texas Express Gathering LLC ("Texas Express Gathering").
(10) Includes our Belle Rose and Wilprise pipelines located in the coastal regions of Louisiana; two Port Arthur pipelines located in southeast Texas; our San Jacinto pipeline located in East Texas; and a pipeline in Colorado associated with our Meeker facility. Transportation services provided by the Belle Rose and Wilprise pipelines are regulated by governmental agencies.
(11) We own a 74.7% consolidated interest in the 30-mile Wilprise pipeline through our majority owned subsidiary, Wilprise Pipeline Company, LLC. We proportionately consolidate our 50% undivided interest in a 45-mile segment of the Port Arthur pipelines. The remainder of these NGL pipelines are wholly owned.

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

The maximum number of barrels per day that our NGL pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our NGL pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 2,700 MBPD, 2,634 MBPD and 2,541 MBPD during the years ended December 31, 2015, 2014 and 2013, respectively.

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

- The *Mid-America Pipeline System* is an NGL pipeline system consisting of four primary segments: the 3,147-mile Rocky Mountain pipeline, the 2,113-mile Conway North pipeline, the 632-mile Ethane-Propane Mix pipeline and the 2,182-mile Conway South pipeline. The Mid-America Pipeline System is present in 13 states: Colorado, Illinois, Iowa, Kansas, Minnesota, Missouri, Nebraska, New Mexico, Oklahoma, Texas, Utah, Wisconsin and Wyoming. The Rocky Mountain pipeline transports mixed NGLs from the Rocky Mountain Overthrust and San Juan Basin areas to the Hobbs NGL hub located on the Texas-New Mexico border. The Conway North segment links the NGL hub at Conway, Kansas to refineries, petrochemical plants and propane markets in the upper Midwest. NGL hubs such as those at Hobbs and Conway provide buyers and sellers a centralized location for the storage and pricing of products, while also providing connections to intrastate and/or interstate pipelines. The Ethane-Propane Mix segment transports ethane/propane mix primarily to petrochemical plants in Iowa and Illinois from the NGL hub at Conway. The Conway South pipeline connects the Conway hub with Kansas refineries and provides bi-directional transportation of NGLs between the Conway and Hobbs hubs. At the Hobbs NGL hub, the Mid-America Pipeline System interconnects with our Seminole Pipeline and Hobbs NGL fractionation and storage facility. The Mid-America Pipeline System is also connected to 18 non-regulated NGL terminals that we own and operate.

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

- The *South Texas NGL Pipeline System* is a network of NGL gathering and transportation pipelines located in South Texas. This system gathers and transports mixed NGLs from natural gas processing plants in South Texas (owned by us or third parties) to our NGL fractionators in South Texas and Mont Belvieu, Texas. In addition, this system transports purity NGL products from our South Texas NGL fractionators to refineries and petrochemical plants located between Corpus Christi, Texas and Houston, Texas and within the Texas City-Houston area, as well as to interconnects with common carrier NGL pipelines. The South Texas NGL Pipeline System connects with our Aegis Ethane Pipeline, which extends our ethane header system from Mont Belvieu, Texas to Corpus Christi, Texas. The South Texas NGL Pipeline System also connects our South Texas NGL fractionators with our storage facility in Mont Belvieu, Texas. The pipeline system includes a 168-mile segment that transports mixed NGLs from our Yoakum natural gas processing plant to our Mont Belvieu NGL fractionation and storage complex. In addition, a 173-mile segment extends from our Yoakum facility to a third party natural gas processing plant located in LaSalle County, Texas, and provides NGL pipeline takeaway capacity for additional third party gas plants.

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

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

- The *ATEX*, or Appalachia-to-Texas Express, pipeline primarily transports ethane in southbound service from four NGL fractionation plants located in Ohio, Pennsylvania and West Virginia to our Mont Belvieu storage complex. The ethane extracted by these fractionation facilities originates from the Marcellus and Utica Shale production areas. ATEX began commercial operations in January 2014 and operates in nine states: Arkansas, Illinois, Indiana, Louisiana, Missouri, Ohio, Pennsylvania, Texas and West Virginia.

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

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

- The *Texas Express Pipeline* extends from Skellytown, Texas to our NGL fractionation and storage complex at Mont Belvieu, Texas. Mixed NGLs from the Rocky Mountains, Permian Basin and Mid-Continent regions are delivered to the Texas Express Pipeline via an interconnect with our Mid-America Pipeline System near Skellytown. The Texas Express Pipeline also transports mixed NGLs from two gathering systems owned by Texas Express Gathering to Mont Belvieu. In addition, mixed NGLs from the Denver-Julesburg Basin are transported to the Texas Express Pipeline using the Front Range Pipeline.

- The *Skelly-Belvieu Pipeline* transports mixed NGLs from Skellytown, Texas to Mont Belvieu, Texas. Our joint venture partner in the Skelly-Belvieu Pipeline assumed operation of the system in January 2016. The Skelly-Belvieu Pipeline receives NGLs through a pipeline interconnect with our Mid-America Pipeline System in Skellytown.

- The *Front Range Pipeline* transports mixed NGLs from natural gas processing plants located in the Denver-Julesburg Basin in Colorado to an interconnect with our Texas Express Pipeline and Mid-America Pipeline System at Skellytown, Texas.

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

- The *Houston Ship Channel Pipeline System* connects our Mont Belvieu complex to our Houston Ship Channel import/export terminals and various third party petrochemical plants, refineries and other pipelines located along the Houston Ship Channel.

- The *Aegis Ethane Pipeline* ("Aegis") was completed in December 2015 and delivers purity ethane to petrochemical facilities along the Texas and Louisiana Gulf Coast. When combined with our South Texas NGL Pipeline System, Aegis provides shippers with access to an ethane header system stretching approximately 500 miles between Corpus Christi, Texas and the Mississippi River in Louisiana. Aegis is supported by customer commitments in excess of 360 MBPD that ramp up over the next four years.

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

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

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

- The *Tri-States NGL Pipeline* transports mixed NGLs from Mobile Bay, Alabama to points near Kenner, Louisiana and was operated by an affiliate of BP p.l.c. as of the end of 2015.

- The *Texas Express Gathering System* is comprised of two gathering systems that deliver mixed NGLs to the Texas Express Pipeline. The Elk City gathering system is comprised of 55 miles of pipeline and gathers mixed NGLs from natural gas processing plants in the Anadarko/Granite Wash production area located in the Texas Panhandle and western Oklahoma. The North Texas gathering system comprises 61 miles of pipeline and gathers mixed NGLs from natural gas processing plants in the Barnett Shale production area in North Texas. An affiliate of Enbridge Energy Partners, L.P. serves as operator of these two NGL gathering systems.

NGL fractionation

We own or have interests in 15 NGL fractionators, located in Texas and Louisiana, which separate mixed NGL streams into purity NGL products for third party customers and also our NGL marketing activities. The primary sources of mixed NGLs fractionated in the U.S. are domestic natural gas processing plants, crude oil refineries and imports of butane and propane mixtures. Mixed NGLs sourced from domestic natural gas processing plants and crude oil refineries are typically transported to NGL fractionation facilities by NGL pipelines and, to a lesser extent, by railcar and truck.

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

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

The following table presents selected information regarding our NGL fractionation facilities at February 1, 2016:

Description of Asset	Location	Our Ownership Interest	Net Plant Capacity (MBPD) (1)	Total Plant Capacity (MBPD)
NGL fractionation facilities:				
Mont Belvieu	Texas	Various (2)	572	670
Shoup and Armstrong	Texas	100.0%	93	93
Hobbs	Texas	100.0%	75	75
Norco	Louisiana	100.0%	75	75
Promix	Louisiana	50.0% (3)	73	145
BRF	Louisiana	32.2% (4)	19	60
Tebone	Louisiana	69.1% (5)	21	30
Total			928	1,148

(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) Six of our eight Mont Belvieu NGL fractionators are held jointly with third parties. We proportionately consolidate a 75% undivided interest in three units and substantially all of a fourth unit. We own a 75% consolidated equity interest in NGL fractionators seven and eight through our majority owned subsidiary, Enterprise EF78 LLC. The remaining two units, NGL fractionators five and six, are wholly owned by us.
(3) Our ownership interest in the Promix fractionator is held indirectly through our equity method investment in Promix.
(4) Our ownership interest in the BRF fractionator is held indirectly through our equity method investment in Baton Rouge Fractionators LLC ("BRF").
(5) We proportionately consolidate our undivided 69.1% interest in the Tebone fractionator.

On a weighted-average basis, overall utilization rates for our NGL fractionators were 90.1%, 89.4% and 88.5% during the years ended December 31, 2015, 2014 and 2013, respectively. We operate all of our NGL fractionators. The following information describes each of our principal NGL fractionators:

- Our *Mont Belvieu* NGL fractionation complex is located at Mont Belvieu, Texas, which is a key hub of the global NGL industry. Our Mont Belvieu NGL fractionation assets process mixed NGLs from several major NGL supply basins in North America, including the Eagle Ford Shale, Rocky Mountains, Mid-Continent, Permian Basin and San Juan Basin. Our Mont Belvieu NGL fractionation complex features connectivity to our network of NGL supply and distribution pipelines, approximately 127 MMBbls of salt dome storage capacity, and access to international markets through our existing LPG export facility and future ethane export facility.

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

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

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

- The *Promix* NGL fractionator receives mixed NGLs via pipeline from natural gas processing plants located in southern Louisiana and along the Mississippi Gulf Coast, including our Neptune and Pascagoula facilities. In addition to the Promix NGL Gathering System, Promix owns three NGL storage caverns and leases a fourth NGL storage cavern. Promix also owns a barge loading facility.

- The *BRF* fractionator receives mixed NGLs from natural gas processing plants located in Alabama, Mississippi and southern Louisiana. In addition, BRF leases a NGL storage cavern.

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

NGL and related product storage facilities

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

The following table presents selected information regarding our NGL and related product storage assets at February 1, 2016:

Storage Capacity by State	Net Usable Storage Capacity (MMBbls)
Texas	142.9
Louisiana	14.0
Kansas	5.8
Mississippi	5.1
Others (1)	6.8
Total (2)	174.6

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

(2) Our aggregate net usable storage capacity includes 15.2 MMBbls held under long-term operating leases at facilities located in Indiana, Kansas, Louisiana and Texas. Approximately 1.5 MMBbls of our net usable storage capacity in Louisiana is held indirectly through our equity method investment in Promix. The remainder of our NGL underground storage caverns and above ground storage tanks are wholly owned.

We operate these facilities, with the exception of certain Louisiana storage locations, the leased Markham facility in Texas and another leased facility in Kansas. Our largest underground storage facility is located in Mont Belvieu, Texas. This facility consists of 37 underground storage caverns used to store and redeliver mixed NGLs and NGL purity, petrochemical and related products for industrial customers located along the upper Texas Gulf Coast. This facility has an aggregate usable storage capacity of approximately 127 MMBbls, a brine system with approximately 21 MMBbls of above-ground brine storage pit capacity and four wells available for brine production.

NGL export terminals and related operations

We own and operate a LPG export terminal and an NGL import facility located on the Houston Ship Channel near Channelview, Texas. We are also constructing an ethane export facility located on the Houston Ship Channel near La Porte, Texas.

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

Houston Ship Channel LPG export terminal and related operations

We own and operate a marine terminal located on the Houston Ship Channel that can load cargoes of fully refrigerated, low-ethane propane and/or butane (collectively referred to as LPG) onto multiple tanker vessels simultaneously. In December 2015, we completed a new refrigeration train that increased the terminal's loading rate for LPG (nameplate capacity) from 16,500 barrels per hour to approximately 27,500 barrels per hour. Completion of this expansion project increased overall loading capabilities at the terminal from 9.0 MMBbls per month to 16.0 MMBbls per month. Our LPG export services continue to benefit from increased NGL supplies produced from domestic shale plays such as the Eagle Ford Shale and international demand for propane as a feedstock in ethylene plant operations and for power generation and heating purposes. On average, LPG loading volumes at this export terminal were 299 MBPD, 248 MBPD and 231 MBPD during the years ended December 31, 2015, 2014 and 2013, respectively.

The primary customer of our Houston Ship Channel LPG export facility is our NGL marketing group, which uses the terminal to assist its export customers in meeting their volume requirements. 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, with shipments originating from our Houston Ship Channel terminal playing a key role. Of the LPG cargoes we loaded for exports during the year ended December 31, 2015, the destination markets were as follows: 33% to the Far East; 29% to Central and South America; 23% to North America and the Caribbean; and 14% to Europe and Africa. Based on available information, our sales of LPG to export customers represented the following percentage of each destination market's approximate total supply: 37% for North America and the Caribbean; 31% for Central and South America; 7% for the Far East; and 6% for Europe and Africa. We expect our export-related sales volumes to increase over the next few years due to existing customer commitments and expanded capacity at our Houston Ship Channel LPG export terminal.

We also own and operate an NGL import facility located at the same terminal as our Houston Ship Channel LPG export terminal. This import facility can offload NGLs from tanker vessels at rates up to 14,000 barrels per hour depending on the product. Our NGL import volumes were minimal during each of the years ended December 31, 2015, 2014 and 2013.

Ethane export terminal

In April 2014, we announced plans to construct a fully refrigerated ethane export facility on the Houston Ship Channel near La Porte, Texas. When completed, the facility, which is supported by long-term contracts, is expected to have an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour and be integrated with our Mont Belvieu NGL fractionation and storage complex. We expect the ethane export facility to begin operations in the third quarter of 2016.

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

Crude Oil Pipelines & Services

Our Crude Oil Pipelines & Services business segment includes approximately 5,400 miles of crude oil pipelines and related operations, crude oil storage and marine terminals and our crude oil marketing activities.

Since the 1970s, U.S. federal law generally prohibited the export of crude oil, except for crude oil sales to Canada and processed condensate (a type of ultralight crude oil that has been processed through a distillation facility). This prohibition was lifted in December 2015. We believe that lifting of the crude oil export ban supports domestic production efforts and creates additional business opportunities for us through the provision of export-related services, including the marketing of domestic crude oil to international customers. We continue to monitor developments in this new business area.

Our Crude Oil Pipelines & Services segment also includes a fleet of 478 tractor-trailer tank trucks, the majority of which we lease and operate, that are used to transport crude oil.

Crude oil pipelines and related operations

Our crude oil pipelines and related operations include crude oil gathering and transportation pipelines in Texas, Oklahoma and New Mexico. These operations also include the EFS Midstream condensate gathering operations that we acquired from Pioneer and Reliance effective July 1, 2015.

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

EFS Midstream provides condensate gathering, processing and stabilization services as well as gathering, treating and compression services for the associated natural gas volumes. In connection with this acquisition, we entered into or amended multiple revenue generating agreements with Pioneer and Reliance having 20-year primary terms. We also entered into similar agreements with other producers connected to the EFS Midstream System. In general, revenues under these agreements are recognized based upon the higher of actual volumes handled or minimum volume commitments. Fees charged for the underlying services are contractually fixed. With respect to those agreements having minimum volume commitments, the producer pays a deficiency fee when its volumes do not meet contractually defined minimum volume thresholds (there are no make-up rights in connection with these agreements). Under certain of the contracts, if actual volumes handled during a period exceed the respective minimum volume commitment, the excess volume serves to reduce future minimum volume commitments (for periods up to two years in the future), thus reducing any potential deficiency fees that the producer might pay in the future.

The following table presents selected information regarding our crude oil pipelines and related operations at February 1, 2016:

Description of Asset	Location(s)	Our Ownership Interest	Pipeline Length (Miles)
Crude oil pipelines:			
Seaway Pipeline (1)	Texas, Oklahoma	50.0% (2)	1,273
Red River System (1)	Texas, Oklahoma	100.0%	1,156
West Texas System (1)	Texas, New Mexico	100.0%	935
South Texas Crude Oil Pipeline System (1)	Texas	100.0%	709
Basin Pipeline (1)	Texas, New Mexico, Oklahoma	13.0% (3)	519
EFS Midstream System	Texas	100.0%	450
Eagle Ford Crude Oil Pipeline System	Texas	50.0% (4)	376
Total			5,418

(1) Transportation services provided by these liquids pipelines are regulated by governmental agencies.
(2) Our ownership interest in the Seaway Pipeline is held indirectly through our equity method investment in Seaway Crude Pipeline Company LLC ("Seaway").
(3) We proportionately consolidate our undivided interest in the Basin Pipeline.
(4) Our ownership interest in the Eagle Ford Crude Oil Pipeline System is held indirectly through our equity method investment in Eagle Ford Pipeline LLC.

The maximum number of barrels per day that our crude oil pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and grades of crude oil being transported). As a result, we measure the utilization rates of our crude oil pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes for these pipelines were 1,474 MBPD, 1,278 MBPD and 1,175 MBPD during the years ended December 31, 2015, 2014 and 2013, respectively.

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

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

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

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

  The Freeport System consists of a marine dock, three pipelines and other related facilities that transport crude oil to and from Freeport, Texas to the Jones Creek terminal. The Texas City System consists of a marine dock, storage tanks, various pipelines and other related facilities that deliver crude oil from Texas City, Texas to Galena Park, Texas and other nearby locations. The intrastate transportation capacity of the Freeport System and Texas City System is approximately 220 MBPD and 800 MBPD, respectively.

  In total, the Seaway Pipeline includes 19 storage tanks located along the Texas Gulf Coast having a combined 8.6 MMBbls of crude oil storage tank capacity (4.3 MMBbls net to our ownership interest). This includes two storage tanks owned by Seaway that are located at our Enterprise Crude Houston ("ECHO") terminal and one tank that Seaway leases from a third party.

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

- The *Red River System* 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. The Red River System is connected to 1.1 MMBbls of crude oil storage capacity that we own and operate.

- The *West Texas System* connects crude oil gathering systems in West Texas and southeast New Mexico to our terminal facility in Midland, Texas. The West Texas System is connected to 0.5 MMBbls of crude oil storage capacity that we own and operate.

- The *South Texas Crude Oil Pipeline System* transports crude oil and condensate originating in South Texas to refineries in the Greater Houston area. The system includes 3.0 MMBbls of crude oil storage capacity. The South Texas Crude Oil Pipeline System also includes our Rancho II pipeline, which was completed in September 2015. The Rancho II pipeline extends 89-miles from Sealy to our ECHO terminal.

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

- The *Eagle Ford Crude Oil Pipeline System* transports crude oil and condensate for producers in South Texas. The system consists of 376 miles of crude oil and condensate pipelines originating in Gardendale, Texas and extending to Corpus Christi, Texas. The system also interconnects with our South Texas Crude Oil Pipeline System in Wilson County, Texas. The Eagle Ford Crude Oil Pipeline System includes an aggregate 4.5 MMBbls of storage capacity across its system (2.2 MMBbls net to our ownership interest) and a marine barge terminal in Corpus Christi.

In September 2015, the joint venture completed an expansion project that effectively looped the Eagle Ford Crude Oil Pipeline System from Gardendale to Corpus Christi and increased the system's capacity to transport light and medium grades of crude oil to over 600 MBPD. Plains All American Pipeline, L.P., our joint venture partner in the pipeline, serves as operator of the system.

In November 2014, the joint venture announced plans to construct a new deep-water marine terminal in Corpus Christi to support the expected increase in crude oil volumes to be shipped via pipeline to the region. The dock is being designed to handle a variety of ocean-going vessels and is expected to be in service in 2018.

- 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 450 miles of gathering pipelines, ten central gathering plants having a combined condensate storage capacity of 0.2 MMBbls, 119 MBPD of condensate stabilization capacity and 780 MMcf/d of associated natural gas treating capacity.

  We acquired EFS Midstream, which owns the EFS Midstream System, effective July 1, 2015 for approximately $2.1 billion. Of the purchase price, $1.1 billion was paid at closing on July 8, 2015 and the final installment of $1.0 billion will be paid no later than the first anniversary of the closing date. Our primary purpose in acquiring the EFS Midstream System was to secure the underlying production, particularly condensate, for our midstream asset network. Under terms of the associated agreements, Pioneer and Reliance have dedicated certain of their Eagle Ford Shale acreage to us under 20-year, fixed-fee gathering agreements that include minimum volume requirement for the first seven years. Pioneer and Reliance have also entered into related 20-year fee-based agreements with us for natural gas transportation and processing, NGL transportation and fractionation, and for condensate and crude oil transportation services.

  In connection with the agreements to acquire EFS Midstream, we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for Pioneer and Reliance, if requested by these 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.

  For additional information regarding our acquisition of EFS Midstream, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Midland-to-Sealy Pipeline

In April 2015, we announced the execution of long-term agreements that support development of a new 24-inch diameter pipeline (the "Midland-to-Sealy" pipeline) that would transport increasing volumes of crude oil and condensate from the Permian Basin to markets in southeast Texas. The new pipeline will originate at our Midland, Texas crude oil terminal and extend 416 miles to our Sealy, Texas storage facility. Volumes arriving at Sealy would then be transported to our ECHO terminal using our Rancho II pipeline. Using the ECHO terminal, shippers will have direct access to every refinery in Houston, Texas City, Beaumont and Port Arthur, as well as our dock facilities. The Midland-to-Sealy pipeline is expected to have an initial transportation capacity of 300 MBPD and is expandable up to 450 MBPD. Committed shippers on the pipeline recently requested to extend the construction timeline by up to one year, and we are currently evaluating our ability to accommodate their needs. The pipeline was originally scheduled to commence operations in mid-2017.

Crude oil storage and marine terminals

We own terminals located in Houston, Midland and Beaumont, Texas and Cushing, Oklahoma that are used to store crude oil for us and our customers. The results of operations from crude oil terminal services are primarily dependent upon the level of volumes stored and the length of time such storage occurs, including the level of firm storage capacity reserved (if any), pumpover volumes and the fees associated with each activity. Fees associated with firm storage capacity reservation agreements are charged regardless of the volume the customer actually stores at the terminal.

Historically, southeast Texas refineries were supplied primarily by waterborne imports of crude oil. Due to prolific North American production, crude oil from the Eagle Ford, Permian, Mid-Continent and Bakken supply basins and Canada is flowing into southeast Texas and displacing waterborne imports of crude oil. As a result, we have experienced a significant increase in North American crude oil deliveries to the Gulf Coast market, which currently lacks sufficient storage capacity and has an inadequate distribution system for handling these varying grades of domestic crude oil. In response, we expanded our Houston Ship Channel and ECHO terminals and have a major expansion project ongoing at our Beaumont Marine West Crude Oil Terminal. Completion of these expansion projects will allow us to provide Gulf Coast refiners with an integrated system featuring supply diversification, significant storage capabilities and a high capacity pipeline distribution system that will be directly connected to customers having an aggregate refining capacity of approximately 3.9 MMBPD.

The following table presents selected information regarding our crude oil terminals at February 1, 2016:

Description of Asset	Location(s)	Our Ownership Interest	Storage Capacity (MMBbls)
Crude oil terminals:			
Houston Ship Channel Terminal	Texas	100.0%	21.4
ECHO terminal	Texas	Various (1)	7.4
Cushing terminal	Oklahoma	100.0%	3.3
Beaumont Marine West Crude Oil Terminal	Texas	100.0%	2.2
Midland terminal	Texas	100.0%	1.9
Morgan's Point terminal	Texas	100.0%	0.3
Total			36.5

(1) We own 100% of 15 tanks at our ECHO terminal having a combined capacity of 6.4 MMBbls. Seaway owns two tanks at our ECHO terminal having a combined capacity of 1.0 MMBbls, of which we have an indirect 50% ownership interest through our equity method investment in Seaway.

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

- The *Houston Ship Channel Terminal* is one of the largest such facilities on the Gulf Coast and provides terminaling services to major integrated oil companies, marketers, distributors and chemical companies. The major products handled at this storage and marine terminal are crude oil and condensates. At February 1, 2016, crude oil and condensates accounted for approximately 89% of the terminal's active storage capacity, with refined products and specialty chemicals accounting for the remaining capacity. We acquired the Houston Ship Channel Terminal as a result of the Oiltanking acquisition.

  Our Houston Ship Channel terminal complex has extensive waterfront access, consisting of six deep-water ship docks and two barge docks. 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 to the east of the Beltway 8 bridge enables us to handle larger vessels than our competitors who are located to the west of the Beltway 8 bridge because our waterfront has fewer draft and beam restrictions. The size and structure of our waterfront at the Houston facility allows us not only to receive and unload products for our storage customers, but also to provide third party docking services for which we receive throughput fees. Our LPG export and NGL import terminals, both of which are a component of our NGL Pipelines & Services business segment, are located at the Houston Ship Channel terminal complex.

  We believe our Houston Ship Channel terminal complex is well positioned to take advantage of changing crude oil logistics along the Gulf Coast as a result of announced third party pipeline construction projects and waterborne and rail movements. In anticipation of this growth, we placed 1.2 MMBbls of crude oil storage capacity into service during 2015 and expect an additional 1.9 MMBbls and 1.6 MMBbls of capacity to enter commercial service in 2016 and 2017, respectively.

- The *ECHO* terminal is located in Houston, Texas and provides storage customers with access to major refineries located in the Houston and Texas City areas. The ECHO terminal also has connections to marine terminals, including our Houston Ship Channel Terminal, that provide access to any refinery on the U.S. Gulf Coast. The ECHO terminal has 7.4 MMBbls of total crude oil storage capacity, 5.4 MMBbls of which was placed into service during 2015.

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

- The *Beaumont Marine West Crude Oil Terminal* is a multi-phase project expected to have a total capacity of up to 6.2 MMBbls of crude oil storage when all currently planned phases have been completed. The terminal is located in Jefferson County, Texas on the Neches River near Beaumont and is part of the same complex as our Beaumont Marine West Refined Products Terminal. The first phase of the project includes pipeline connections and manifold infrastructure and the construction of a new finger pier with two new deep-water docks. The new docks will be configured to load and unload crude oil and related products at rates sufficient to accommodate expected growth at the terminal. Storage tanks representing 2.2 MMBbls of capacity were completed in January 2016.

- The *Midland terminal* provides crude oil storage, pumpover and trade documentation services. The Midland, Texas terminal has an aggregate storage capacity of 1.9 MMBbls through the use of 15 above-ground storage tanks.

Crude oil marketing activities

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil purchased either directly from producers or from others on the open market. The results of operations from our crude oil marketing activities are primarily dependent upon the difference, or spread, between crude oil sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location or crude oil quality. We also use derivative instruments to mitigate our exposure to commodity price risks associated with our crude oil marketing activities. For a discussion of our commodity hedging program, see Part II, Item 7A of this annual report.

In March 2014, the U.S. Department of Commerce allowed us to begin exporting processed condensate. Our first cargo was loaded in July 2014. In total, we loaded 15.9 MMBbls and 3.7 MMBbls of processed condensate for export in 2015 and 2014, respectively.

Natural Gas Pipelines & Services

Our Natural Gas Pipelines & Services business segment includes approximately 19,100 miles of natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. We lease underground salt dome natural gas storage facilities located in Texas and Louisiana and own an underground salt dome storage cavern in Texas, all of which are important to our natural gas pipeline operations. This segment also includes our related natural gas marketing activities.

Natural gas pipelines and related storage assets

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

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

The following table presents selected information regarding our natural gas pipelines and related storage assets at February 1, 2016:

				Approximate Net Capacity	
Description of Asset	**Location(s)**	**Our Ownership Interest**	**Length (Miles)**	**Pipelines (MMcf/d)**	**Usable Storage (Bcf)**
Natural gas pipelines and storage:					
Texas Intrastate System (1)	Texas	Various (2)	8,021	6,580	12.9
Acadian Gas System (1)	Louisiana	100.0% (3)	1,323	3,100	1.3
Jonah Gathering System	Wyoming	100.0%	753	2,360	--
Piceance Basin Gathering System	Colorado	100.0%	195	1,800	--
San Juan Gathering System	New Mexico, Colorado	100.0%	6,089	1,750	--
White River Hub (4)	Colorado	50.0% (5)	10	1,500	--
Haynesville Gathering System	Louisiana, Texas	100.0%	359	1,300	--
Fairplay Gathering System (1)	Texas	100.0% (6)	275	285	--
Carlsbad Gathering System	Texas, New Mexico	100.0%	923	220	--
Indian Springs Gathering System (1)	Texas	80.0% (7)	174	160	--
Delmita Gathering System	Texas	100.0%	200	145	--
South Texas Gathering System	Texas	100.0%	518	143	--
Big Thicket Gathering System (1)	Texas	100.0%	253	60	--
Total			19,093		14.2

(1) Transportation services provided by these systems, in whole or part, are regulated by governmental agencies.
(2) Of the 8,021 miles comprising the Texas Intrastate System, we lease 240 miles from a third party. We proportionately consolidate our undivided interests, which range from 22% to 80%, in 1,459 miles of pipeline. Our Wilson natural gas storage facility consists of five underground salt dome natural gas storage caverns with 12.9 Bcf of usable storage capacity, four of which (comprising 6.9 Bcf of usable capacity) are held under an operating lease that expires in January 2028. The remainder of our Texas Intrastate System is wholly owned.
(3) The Acadian Gas System is wholly owned except for an underground salt dome natural gas storage facility that we hold under an operating lease that expires in December 2018.
(4) Interstate transportation service provided by this facility is regulated by governmental agencies.
(5) Our ownership interest in the White River Hub facility is held indirectly through our equity method investment in White River Hub, LLC ("White River Hub").
(6) The Fairplay Gathering System includes approximately 52 miles of pipeline held under an operating lease.
(7) We proportionately consolidate our 80% undivided interest in the Indian Springs Gathering System.

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

On a weighted-average basis, overall utilization rates for our natural gas pipelines were approximately 59.3%, 60.5% and 65.2% during the years ended December 31, 2015, 2014 and 2013, respectively. These utilization rates represent actual natural gas volumes delivered as a percentage of our nominal delivery capacity and do not reflect firm capacity reservation agreements where throughput capacity is reserved whether or not the shipper actually utilizes such capacity.

The following information describes each of our principal 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 6,809-mile Enterprise Texas pipeline system, the 629-mile Channel pipeline system and the 583-mile Waha gathering system. The Texas Intrastate System gathers, transports and stores natural gas from supply basins in Texas such as the Eagle Ford and Barnett Shales for redelivery to local gas distribution companies and electric generation, industrial and municipal consumers as well as to connections with other intrastate and interstate pipelines. The Texas Intrastate System serves various commercial markets in Texas, including Corpus Christi, San Antonio/Austin, Beaumont/Orange and Houston, including the Houston Ship Channel industrial market. The Wilson natural gas storage facility, which is an important part of the Texas Intrastate System, is comprised of a network of underground salt dome storage caverns located in Wharton County, Texas.

- The *Acadian Gas System* transports, stores and markets natural gas in Louisiana. The Acadian Gas System is comprised of the 589-mile Cypress pipeline, 437-mile Acadian pipeline, 271-mile Haynesville Extension pipeline and 26-mile Enterprise Pelican pipeline. The Acadian Gas System includes a leased underground salt dome natural gas storage cavern located at Napoleonville, Louisiana. The Acadian Gas System links natural gas supplies from Louisiana (e.g., from Haynesville Shale supply basin) and offshore Gulf of Mexico developments with local gas distribution companies, electric generation plants and industrial customers located primarily in the Baton Rouge/New Orleans/Mississippi River corridor.

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

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

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

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

- The *Haynesville Gathering System* consists of the 216-mile State Line gathering system, the 73-mile Southeast Mansfield gathering system and the 70-mile Southeast Stanley gathering system. The Haynesville Gathering System gathers natural gas produced from the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations in Louisiana and eastern Texas for delivery to regional markets, including (through an interconnect with the Haynesville Extension pipeline) markets served by our Acadian Gas System.

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

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

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

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

Natural gas marketing activities

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

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

Our Petrochemical & Refined Products Services business segment includes (i) propylene fractionation and related operations, including 674 miles of pipelines; (ii) a butane isomerization complex, associated deisobutanizer units and related pipeline assets; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines aggregating approximately 4,200 miles, terminals and related marketing activities; and (v) marine transportation.

Propylene fractionation and related operations

Our propylene fractionation and related operations consist of seven propylene fractionation plants, including pipeline systems aggregating 674 miles, and related petrochemical marketing activities. This business includes an export facility and associated above-ground storage spheres for polymer grade propylene ("PGP") located in Seabrook, Texas. We operate all of our propylene fractionation and related assets except for the Lake Charles PGP Pipeline in Louisiana and the export facility in Seabrook.

In general, propylene fractionation plants separate refinery grade propylene ("RGP"), which is a mixture of propane and propylene, into either PGP or chemical grade propylene ("CGP") along with by-products of propane and mixed butane. PGP and CGP can also be produced as a by-product of ethylene production. 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 and 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.

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

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

The following table presents selected information regarding our propylene fractionation facilities at February 1, 2016:

Description of Asset	Location(s)	Our Ownership Interest	Net Plant Capacity (MBPD)	Total Plant Capacity (MBPD)
Propylene fractionation facilities:				
Mont Belvieu (six units)	Texas	Various (1)	81	95
BRPC (one unit)	Louisiana	30.0% (2)	7	23
Total			88	118

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

We produce PGP at our Mont Belvieu, Texas propylene fractionation facility and CGP at our BRPC facility located in Baton Rouge, Louisiana. On a weighted-average basis, overall utilization rates of our propylene fractionation facilities were approximately 80.5%, 84.7% and 87.4% during the years ended December 31, 2015, 2014 and 2013, respectively.

The following table presents selected information regarding our petrochemical pipelines at February 1, 2016:

Description of Asset	Location(s)	Ownership Interest	Length (Miles)
Petrochemical pipelines:			
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%	149
Propylene Splitter PGP Distribution System	Texas	100.0%	34
Lake Charles PGP Pipeline	Louisiana	50.0% (1)	26
La Porte PGP Pipeline	Texas	50.0% (2)	20
Sabine Pipeline	Texas, Louisiana	100.0%	15
Total			674

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

The maximum number of barrels per day that our petrochemical pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our petrochemical pipelines in terms of net throughput, which is based on our ownership interest. Total net throughput volumes were 126 MBPD, 124 MBPD and 118 MBPD during the years ended December 31, 2015, 2014 and 2013, respectively.

The Lou-Tex Propylene pipeline is used to transport CGP from Sorrento, Louisiana to Mont Belvieu, Texas. 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.

The North Dean Pipeline System transports RGP from Mont Belvieu, Texas, to Point Comfort, Texas. In June 2015, we announced plans to convert the 149-mile North Dean Pipeline from RGP service to PGP service. The conversion is scheduled for completion in the first quarter of 2017.

In June 2015, we also announced plans for the construction of a new 65-mile, 10-inch diameter pipeline, which will transport RGP between Sorrento and Breaux Bridge, Louisiana. This pipeline is scheduled for completion in the first quarter of 2017. In addition, rail receipt facilities in Mont Belvieu are also being expanded to give us the capability to unload up to 80 RGP rail cars per day.

Propane Dehydrogenation Facility

In June 2012, we announced plans to build a propane dehydrogenation ("PDH") facility, with the capacity to produce up to 1.65 billion pounds per year (or approximately 750 thousand metric tons per year or 25 MBPD) of PGP. The PDH facility is expected to consume approximately 35 MBPD of propane as feedstock and be located adjacent to our Mont Belvieu complex. The new facility will be integrated with our existing propylene fractionation facilities, which will provide operational reliability and flexibility for both the PDH facility and the fractionation facilities. The PDH facility, which is underwritten by long-term fee-based, minimum volume agreements, will also be integrated with our PGP storage facilities, pipeline system and export terminal. Initially, we expected to begin commercial operations at this facility in third quarter of 2015.

In July 2013, we executed a contract with Foster Wheeler USA Corporation to serve as the general contractor responsible for the engineering, procurement, construction and installation of the PDH facility. In November 2014, Foster Wheeler merged with AMEC plc to form Amec Foster Wheeler plc, and the general contractor Foster Wheel USA Corporation 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. AFW continues to be responsible for the limited role of completing all remaining engineering, and for providing services to support disciplines such as construction field engineering, project controls and supply chain.

In February 2016, OPD provided us with new estimates with respect to the cost of the project and the schedule to complete construction, begin commissioning activities and begin commercial operations. Currently, we expect construction of the PDH facility to be completed in the first quarter of 2017 with commercial operations expected to begin in the second quarter of 2017.

Butane isomerization and deisobutanizer operations

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

The primary uses of isobutane are for the production of propylene oxide, isooctane, isobutylene and alkylate for motor gasoline. The demand for commercial isomerization services depends upon the industry's requirements for isobutane and high-purity isobutane in excess of the isobutane produced through the process of NGL fractionation and refinery operations. The processing capacity of our isomerization facility is 116 MBPD. On a weighted-average basis, utilization rates for this facility were approximately 82.8%, 80.2% and 81.0% during the years ended December 31, 2015, 2014 and 2013, respectively.

We use certain DIB units to fractionate mixed butanes produced from our NGL fractionation activities, from imports and from other sources into isobutane and normal butane. The operating flexibility provided by our multiple standalone DIBs enables us to take advantage of fluctuations in demand and prices for different types of butane. We measure the utilization of our standalone DIB units in terms of processing volumes, which averaged 79 MBPD, 82 MBPD and 67 MBPD for the years ended December 31, 2015, 2014 and 2013, respectively. Standalone DIB processing volumes have increased as a result of increased NGL fractionation volumes at our Mont Belvieu complex.

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

Octane enhancement and high purity isobutylene production facilities

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

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 combined isooctane, isobutylene and MTBE production volumes, which averaged 15 MBPD, 15 MBPD and 18 MBPD for the years ended December 31, 2015, 2014 and 2013, respectively. Octane enhancement production volumes for 2015 and 2014 were adversely impacted by extended maintenance outages in each of these years.

We also own and operate a facility located on the Houston Ship Channel that produces up to 4 MBPD of high purity isobutylene ("HPIB") and includes an associated storage facility with 0.6 MMBbls of storage capacity. The primary feedstock for this plant, an isobutane/isobutylene mix, is produced by our Mont Belvieu octane enhancement facility. HPIB is used in the formulation of polyisobutylene, which is used in the manufacture of lubricants and rubber. In general, we sell HPIB at market-based prices with a cost-based floor. On a weighted-average basis, utilization rates for this facility were 54.8%, 47.2% and 40.6% for the years ended December 31, 2015, 2014 and 2013, respectively.

Refined products pipelines

Refined products pipelines include our TE Products Pipeline and an investment in Centennial Pipeline LLC ("Centennial"). The refined products transported by these pipelines are produced by refineries and primarily include motor gasoline and distillates. The results of operations for these pipelines are primarily dependent upon the volume of products transported and the level of fees charged to shippers. The tariffs charged for such services are either contractual or regulated by governmental agencies, including the FERC.

The following table presents selected information regarding our refined products pipelines and related terminals at February 1, 2016:

Description of Asset	Location(s)	Our Ownership Interest	Length (Miles)	Net Usable Storage Capacity (MMBbls)
Refined products pipelines and terminals:				
TE Products Pipeline (1,2)	Texas to Midwest and Northeast U.S.	100.0%	3,396	19.2
Centennial Pipeline (2)	Texas to Illinois	50.0% (3)	795	1.2
Total			4,191	20.4

(1) In addition to the 19.2 MMBbls of refined products storage capacity presented in the table, we have 3.7 MMBbls of storage capacity that is used to support NGL operations on our TE Products Pipeline. Our NGL storage and terminal assets are accounted for under the NGL Pipelines & Services business segment.

(2) Interstate and intrastate transportation services provided by the TE Products Pipeline and interstate transportation services provided by the Centennial Pipeline are regulated by governmental agencies.

(3) Our ownership interest in the Centennial Pipeline is held indirectly through our equity method investment in Centennial.

The maximum number of barrels per day that our refined products pipelines can transport depends on the operating balance achieved at a given point in time between various segments of each system (e.g., demand levels at each delivery point and the mix of products being transported). As a result, we measure the utilization rates of our refined products pipelines in terms of net throughput, which is based on our ownership interest. Aggregate net throughput volumes by product type for the TE Products Pipeline and Centennial Pipeline were as follows for the periods presented:

	For the Year Ended December 31,		
	2015	2014	2013
Refined products transportation (MBPD)	444	412	373
Petrochemical transportation (MBPD)	144	137	120
NGL transportation (MBPD)	55	65	72

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

- The *TE Products Pipeline* is a 3,396-mile pipeline system comprised of 3,077 miles of interstate pipelines and 319 miles of intrastate Texas pipelines. Refined products and certain NGLs are transported from the upper Texas Gulf Coast to Seymour, Indiana. From Seymour, segments of the TE Products Pipeline extend to Chicago, Illinois; Lima, Ohio; Selkirk, New York; and near Philadelphia, Pennsylvania. East of Seymour, Indiana, the TE Products Pipeline is primarily dedicated to NGL transportation service.

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

- The *Centennial Pipeline* is a refined products pipeline that extends from an origination facility located on our TE Products Pipeline in Beaumont, Texas, to Bourbon, Illinois. The Centennial Pipeline includes a refined products storage terminal located near Creal Springs, Illinois with a gross storage capacity of 2.3 MMBbls (or 1.2 MMBbls net to our ownership interest). This pipeline is currently idled; however, we are evaluating projects that would repurpose the system.

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

Refined products terminals

We own and operate two refined products storage and export facilities located in Beaumont, Texas and refined products marketing and distribution terminals located in Alabama and Mississippi.

The results of operations from our refined products export facilities are primarily dependent upon the volume handled and the associated fees we charge for loading services. Customers are typically billed a fee per unit of volume loaded and revenue is recorded in the period the loading services are provided. The results of operations from our refined products terminaling services are primarily dependent upon the level of volumes a customer stores at each terminal and the length of time such storage occurs, including the level of firm storage capacity reserved (if any), pumpover volumes and the fees associated with each activity. Fees associated with firm storage capacity reservation agreements are charged regardless of the volume the customer actually stores at the terminal. With respect to our export terminal operations, revenue may also include deficiency fees charged to customers that reserve capacity at our export facility and later fail to use such capacity. Deficiency fee revenue is recognized when the customer fails to utilize the specified export capacity as required by contract.

The principal assets of this business are the Beaumont Marine East and West Refined Products Terminals. Both facilities are located on the Neches River near Beaumont, Texas, with the East terminal located in Orange County, Texas and the West terminal located in Jefferson County, Texas. Due to their close proximity to each other, the terminals are operated as a single asset from a commercial standpoint. We acquired the Beaumont Marine West Refined Products Terminal as a result of the Oiltanking acquisition. On a combined basis, the terminals include three deep-water ship docks and two barge docks and have access to more than 4.9 MMBbls of refined products storage capacity. In addition, these terminals have access to 11.8 MMBbls of refined products storage capacity at locations along our TE Products Pipeline between Beaumont and Houston, Texas.

With their strategic location and capabilities, the Beaumont Marine East and West Refined Products Terminals provide optionality for exporters, allowing them to capture added value from the evolving fundamentals of the domestic and international refined products markets while avoiding potentially longer wait times associated with Houston Ship Channel refined products export facilities.

Refined products marketing activities

Our refined products marketing activities generate revenues from the sale and delivery of refined products obtained on the open market. The results of operations from our refined products marketing activities are primarily dependent upon the difference, or spread, between product sales prices and the associated purchase and other costs, including those costs attributable to the use of our other assets. In general, we sell our refined products at market-based prices, which may include pricing differentials for factors such as delivery location. We use derivative instruments to mitigate our exposure to commodity price risks associated with our refined products marketing activities. 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 59 tow boats and 130 tank barges that are used to transport refined products, crude oil, asphalt, condensate, heavy fuel oil, LPG and other petroleum products along key inland and intracoastal U.S. waterways. The marine transportation industry uses tow boats as power sources and tank barges for freight capacity.

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

Our fleet of marine vessels operated at an average utilization rate of 87.9%, 93.1% and 93.9% during the years ended December 31, 2015, 2014 and 2013, 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, Item 1 and 2 discussion.

Offshore Pipelines & Services

On July 24, 2015, we completed the sale of our Offshore Business to Genesis, which primarily consisted of our Offshore Pipelines & Services business segment, for approximately $1.53 billion in cash. Our Offshore Business served drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Alabama, Louisiana, Mississippi and Texas. These operations included approximately 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms. Our results of operations reflect ownership of the Offshore Business through July 24, 2015. For additional information regarding sale of the Offshore Business, see Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Regulatory Matters

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

Safety Matters

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

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

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

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

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

We are subject to DOT pipeline integrity management regulations that specify how companies should assess, evaluate, validate and maintain the integrity of pipeline segments that, in the event of a release, could impact High Consequence Areas ("HCAs"). HCAs include populated areas, unusually sensitive areas and commercially navigable waterways. The regulation requires the development and implementation of an integrity management program that utilizes internal pipeline inspection techniques, pressure testing or other equally effective means to assess the integrity of pipeline segments in HCAs. These regulations also require periodic review of HCA pipeline segments to ensure that adequate preventative and mitigative measures exist and that companies take prompt action to address integrity issues raised in the assessment and analysis process. We have identified our pipeline segments in HCAs and developed an appropriate integrity management program for such assets.

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 increases penalties for non-compliance with its regulations for a single violation from $100,000 to $200,000 and imposes a maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm of $2 million per incident. In addition, the act includes additional safety requirements for newly constructed pipelines. The act also provides for (i) additional pipeline damage prevention measures, (ii) allowing the Secretary of Transportation to require automatic and remote-controlled shut-off valves on new pipelines, (iii) requiring the Secretary of Transportation to evaluate the effectiveness of expanding pipeline integrity management and leak detection requirements, (iv) improving the way the DOT and pipeline operators provide information to the public and emergency responders and (v) reforming the process by which pipeline operators notify federal, state and local officials of pipeline accidents.

In total, our pipeline integrity costs for the years ended December 31, 2015, 2014 and 2013 were $92.7 million, $99.0 million and $128.0 million, respectively. Of these annual totals, we charged $54.7 million, $59.7 million and $70.4 million to operating costs and expenses during the years ended December 31, 2015, 2014 and 2013, 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 $122.0 million for 2016.

DOT regulations have incorporated by reference the American Petroleum Institute Standard 653 ("API 653") as the industry standard for the inspection, repair, alteration and reconstruction of storage tanks. API 653 requires regularly scheduled inspection and repair of such tanks. These periodic tank maintenance requirements may result in significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our storage tanks.

In January 2015, the White House announced plans to regulate methane emissions attributable to the upstream oil and gas industry, including activities related to gathering and compression, as a greenhouse gas. See "Climate Change Debate" within this Regulatory Matters section. This announcement indicated that the DOT through its Pipeline and Hazardous Materials Safety Administration ("PHMSA"), will be issuing new natural gas regulations with the intent to improve safety as well as to reduce methane emissions. A PHMSA reauthorization bill is scheduled for consideration by the Senate in 2016. Until the bill is passed in its final form 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; and comparable or analogous state and local laws and regulations. Such laws and regulations affect many aspects of our present and future operations, and generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals with respect to air emissions, water quality, wastewater discharges and solid and hazardous waste management. Failure to comply with these requirements may expose us to fines, penalties and/or interruptions in our operations that could have a material adverse effect on our financial position, results of operations and cash flows.

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

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

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

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

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

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

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

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

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

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

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

FERC Regulation – Liquids Pipelines

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

The ICA prescribes that the interstate rates we charge for transportation on these interstate liquids pipelines must be just and reasonable, and that the rules applied to our services not unduly discriminate against or confer any undue preference upon any shipper. 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. During the five-year period commencing July 1, 2011 and ending June 30, 2016, we have been permitted by the FERC to adjust these indexed rate ceilings annually by the PPI plus 2.65%. In December 2015, the FERC established PPI plus 1.23% as the index for the five-year period commencing July 1, 2016. As an alternative to this indexing methodology, we may also choose to support changes in our rates based on a cost-of-service methodology, by obtaining advance approval to charge "market-based rates," or by charging "settlement rates" agreed to by all affected shippers.

In June 2013, certain parties filed a complaint at the FERC against Enterprise TE Products Pipeline Company LLC ("Enterprise TE") alleging that Enterprise TE's cancellation of certain distillate and jet fuel transportation services violated a provision of a settlement agreement and requested reinstatement of the transportation services and damages. In October 2013, the FERC issued an order holding that Enterprise TE violated the provision in the settlement agreement. While the FERC found that it did not have authority to require Enterprise TE to reinstate the cancelled services, it set the case for an evidentiary hearing to determine if any monetary damages were appropriate. Certain parties requested rehearing of the FERC's finding that it lacked authority to reinstate the cancelled services. In December 2013, Enterprise TE filed a petition for review of the FERC's October 2013 order with the United States Court of Appeals for the District of Columbia Circuit. Enterprise TE has subsequently negotiated settlements that have resolved the complaints; however, the rehearing request and Enterprise TE's petition for review to the D.C. Circuit remain pending. We are unable to predict the outcome of this proceeding.

In March 2011, Enterprise TE filed an application with the FERC for authorization to charge market-based rates for the interstate transportation of refined petroleum products to Arcadia, Louisiana; Little Rock, Arkansas; and Jonesboro, Arkansas. In March, 2014, the FERC rejected Enterprise TE's market-based rate application. In April 2014, Enterprise TE filed a request for rehearing of the March 2014 order, which the FERC denied in February 2016. We are unable to predict the outcome of this proceeding.

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

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

In October 2013, Seaway and certain committed rate shippers filed briefs on exceptions objecting to this committed shipper rate aspect of the ALJ's Initial Decision, and also challenging various aspects of the cost of service determinations in the Initial Decision. In February 2014, the FERC issued an order reversing the Initial Decision with respect to the committed rate issue, reiterating its policy of honoring contracts executed between pipelines and committed shippers and remanding the remaining issues to the ALJ for further review. In May 2014, the ALJ issued an initial decision on remand, which largely repeated its prior findings, including as to the committed shipper rates. In February 2016, the FERC again reversed the ALJ decision with respect to the committed rate issue and upheld Seaway's committed rates. The FERC's February 2016 order also ruled for and against Seaway on various issues related to the uncommitted rates and required Seaway to submit, by March 17, 2016, a compliance filing calculating new uncommitted rates consistent with the FERC's order.

Seaway has filed two applications with the FERC for authorization to charge market-based rates for the interstate transportation of crude oil from Cushing, Oklahoma to the Gulf Coast. In February 2014, the FERC upheld an order it issued in May 2012 that denied Seaway's initial application for market-based rate setting authority, without prejudice to Seaway refiling its application based on the guidance provided in the February order. In September 2015, the FERC denied the request for rehearing of its February 2014 order. In November 2015, the Air Transport Association of America, Inc. filed a petition for review of the FERC's February 2014 and September 2015 orders with the D.C. Circuit. In December 2014, Seaway submitted a new application requesting market-based rate setting authority. In September 2015, the FERC issued an order setting the matter for hearing, which is currently scheduled to begin in July 2016. In light of the fact-intensive and complex nature of these types of market-based rate applications, we are unable to predict the ultimate outcome on the rates Seaway charges its shippers.

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

FERC Regulation – Natural Gas Pipelines and Related Matters

Certain of our intrastate natural gas pipelines, including our Texas Intrastate System and our Acadian Gas System, are subject to regulation by the FERC under the Natural Gas Policy Act of 1978 ("NGPA"), in connection with the transportation and storage services they provide pursuant to Section 311 of the NGPA. Under Section 311 of the NGPA, and the FERC's implementing regulations, an intrastate pipeline may transport gas "on behalf of" an interstate pipeline company or any local distribution company served by an interstate pipeline, without becoming subject to the FERC's broader regulatory authority under Natural Gas Act of 1938 ("NGA"). These services must be provided on an open and nondiscriminatory basis, and the rates charged for these services may not exceed a "fair and equitable" level as determined by the FERC in periodic rate proceedings.

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 energy market manipulation. The Federal Trade Commission and the Commodity Futures Trading Commission ("CFTC") have also issued rules and regulations prohibiting energy market manipulation. We believe that our gas sales activities are in compliance with all applicable regulatory requirements.

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

State Regulation of Pipeline Transportation Services

Transportation services rendered by our intrastate liquids and natural gas pipelines are subject to regulation in many states, including Alabama, Colorado, Illinois, Kansas, Louisiana, Minnesota, Mississippi, New Mexico, Oklahoma, Texas and Wyoming. The Texas Railroad Commission has the authority to regulate the rates and terms of service for our intrastate natural gas transportation operations in Texas. Although the applicable state statutes and regulations vary widely, they generally require that intrastate pipelines publish tariffs setting forth all rates, rules and regulations applying to intrastate service, and generally require that pipeline rates and practices be reasonable and nondiscriminatory. Shippers may challenge tariff rates and practices on our intrastate pipelines.

Federal Regulation of Marine Operations

The operation of tow boats, barges and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, among other things, the risk of collision and allision, which may precipitate claims for personal injury, cargo, contract, pollution, third party claims and property damages to vessels and facilities.

We are subject to the Jones Act and other federal laws that restrict maritime transportation between U.S. departure and destination points to vessels built and registered in the U.S. and owned and manned by U.S. citizens. As a result of this ownership requirement, we are responsible for monitoring the foreign ownership of our common units and other partnership interests. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels. In addition, the USCG and American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. Our marine operations are also subject to the Merchant Marine Act of 1936, which under certain conditions would allow the U.S. government to requisition our marine assets in the event of a national emergency.

Climate Change Debate

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

In response to scientific studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases, including gases associated with oil and gas production such as carbon dioxide, methane and nitrous oxide among others, may be contributing to a warming of the earth's atmosphere and other adverse environmental effects, various governmental authorities have considered or taken actions to reduce emissions of greenhouse gases. For example, the EPA has taken action under the CAA to regulate greenhouse gas emissions. In addition, certain states (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 and the U.S. has been actively 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 will continue to result in additional actions involving greenhouse gases.

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

Competition

NGL Pipelines & Services

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

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

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 trading platforms and independent crude oil gathering and marketing companies. The crude oil business can be characterized by strong competition for crude oil volumes. Competition is based primarily on quality of customer service, competitive pricing and proximity to customers and market hubs.

Natural Gas Pipelines & Services

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

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. Generally, our propylene fractionation business competes in terms of the level of toll processing fees charged and access to pipeline and storage infrastructure. Our petrochemical marketing activities encounter competition from fully integrated oil companies and various petrochemical companies. Our petrochemical marketing competitors have varying levels of financial and personnel resources and competition generally revolves around price, quality of customer service, logistics and location.

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

With respect to our TE Products Pipeline, 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 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.

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 our Mont Belvieu facility, 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 (e.g., the Texas Intrastate System) as well as storage levels and natural gas 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.

- Extreme temperatures and ice during the winter months can negatively affect our 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 NGL fractionators are constructed) and (ii) parcels in which our interests and those of our affiliates are derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. The fee sites upon which our significant facilities are located have been owned by us or our predecessors in title for many years without any material challenge known to us relating to title to the land upon which the assets are located, and we believe that we have satisfactory title to such fee sites. We and our affiliates have no knowledge of any material challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our rights pursuant to any material lease, easement, right-of-way, permit or license, and we believe that we have satisfactory rights pursuant to all of our material leases, easements, rights-of-way, permits and licenses.

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. You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. You may obtain information regarding the Public Reference Room by calling the SEC at (800) SEC-0330. In addition, the SEC maintains a website at www.sec.gov that contains reports and other information regarding registrants that file electronically with the SEC.

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

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

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

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

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

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

Item 1A. *Risk Factors.*

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

Risks Relating to Our Business

Changes in demand for and 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 counterparties 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 extremely volatile in recent years, and we expect that volatility to continue. For example, crude oil prices (based on WTI as measured by the NYMEX) ranged from a high of $61.43 per barrel to a low of $34.73 per barrel in 2015. For January 2016, WTI crude oil prices ranged from a high of $36.76 per barrel to a low of $26.55 per barrel. Likewise, natural gas prices (based on Henry Hub Inside FERC index prices) ranged from a high of $3.23 per MMBtu to a low of $1.76 per MMBtu in 2015. Using the same index, natural gas prices for January 2016 ranged from a high of $2.47 per MMBtu to a low of $2.09 per MMBtu.

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

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

The crude oil, natural gas and NGLs currently transported, gathered or processed at our facilities originate 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.

For a discussion regarding our current commercial outlook for 2016, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations – General Outlook for 2016" 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 refined products, NGL and marine transportation businesses may compete with other pipelines and marine transportation companies in the areas they serve. We also compete with railroads and third party trucking operations in certain of the areas we serve. Competitive pressures may adversely affect our tariff rates or volumes shipped. Also, substantial new construction of inland marine vessels could create an oversupply and intensify competition for our marine transportation business.

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

In our natural gas gathering business, we encounter competition in obtaining contracts to gather natural gas supplies, particularly new supplies. Competition in natural gas gathering is based in large part on reputation, efficiency, system reliability, gathering system capacity and pricing arrangements. Our key competitors in the 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.

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

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

As of December 31, 2015, we had $20.15 billion in principal amount of consolidated senior long-term debt outstanding, $1.47 billion in principal amount of junior subordinated debt outstanding and $1.11 billion in short-term commercial paper notes outstanding. The amount of our future debt could have significant effects on our operations, including, among other things:

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

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

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

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

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

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

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

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

Our ability to access capital markets to raise capital on favorable terms could be affected by our debt level, when such debt matures, and by prevailing market conditions. Moreover, if the rating agencies were to downgrade our credit ratings, we could experience an increase in our borrowing costs, difficulty assessing capital markets and/or a reduction in the market price of our securities. Such a development could adversely affect our ability to obtain financing for working capital, capital expenditures or acquisitions, or to refinance existing indebtedness. If we are unable to access the capital markets on favorable terms in the future, we might be forced to seek extensions for some of our short-term debt obligations or to refinance some of our debt obligations through bank credit, as opposed to long-term public debt securities or equity securities. The price and terms upon which we might receive such extensions or additional bank credit, if at all, could be more onerous than those contained in existing debt agreements. Any such arrangements could, in turn, increase the risk that our leverage may adversely affect our future financial and operating flexibility and thereby impact our ability to pay cash distributions at expected levels.

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

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

We will require substantial new capital to finance the future development and acquisition of assets and businesses. For example, our capital spending for 2015 reflected approximately $5.0 billion of cash payments for capital projects and other investments. Based on information currently available, we expect our total capital spending for 2016 to approximate $3.8 billion to $4.1 billion, which includes the $1.0 billion final installment payable in connection with the EFS Midstream acquisition and $275 million for sustaining capital expenditures. Any limitations on our access to capital may impair our ability to execute this growth strategy. If our cost of debt or equity capital becomes too expensive, our ability to develop or acquire accretive assets will be limited. We also may not be able to raise the necessary funds on satisfactory terms, if at all.

Any 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 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.

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

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

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

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

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

Our construction of new assets is subject to 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;

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

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

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

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

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

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

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

Many 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.

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

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

If one or more facilities or electronic systems that we own or that deliver products to us or that supply our facilities are damaged by severe weather or any other disaster, accident, catastrophe, terrorist or cyber attack or event, our operations could be significantly interrupted. These interruptions could involve significant damage to people, property or the environment, and repairs could take from a week or less for a minor incident to six months or more for a major interruption. Additionally, some of the storage contracts that we are a party to obligate us to indemnify our customers for any damage or injury occurring during the period in which the customers' product is in our possession. Any event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions and, accordingly, adversely affect the market price of our common units.

We believe that EPCO maintains adequate insurance coverage on our behalf, although insurance will not cover many types of interruptions that might occur, will not cover amounts up to applicable deductibles and will not cover all risks associated with certain of our products. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage.

In the future, circumstances may arise whereby EPCO may not be able to renew existing insurance policies on our behalf or procure other desirable insurance on commercially reasonable terms, if at all. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results of operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

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

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

To the extent that we hedge our commodity price and interest rate exposures, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, hedging activities can result in losses that might be material to our financial condition, results of operations and cash flows. Such losses could occur under various circumstances, including those situations where a counterparty does not perform its obligations under a hedge arrangement, the hedge is not effective in mitigating the underlying risk, or our risk management policies and procedures are not followed. Adverse economic conditions, such as the rapid declines in crude oil prices during the fourth quarter of 2014, depressed prices throughout 2015 and further rapid declines during the fourth quarter of 2015 and beginning of 2016, increase the risk of nonpayment or performance by our hedging counterparties.

See 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 counterparties do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, petrochemicals, refined products and crude oil 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, such as those experienced throughout 2015 and that we continue to experience at the beginning of 2016, increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings or small-scale companies. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk. In 2015, approximately 4.5% of our consolidated revenues were associated with 22 independent oil and gas producers with sub-investment grade credit ratings.

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

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 non-compliance with our risk management policies could result in significant financial losses.

When engaged in marketing activities, it is our policy to maintain physical commodity positions that are substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to earn a margin for the commodity purchased by selling the same commodity for physical delivery to third party users, such as producers, wholesalers, independent refiners, marketing companies or major oil companies. These policies and practices cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover these transactions. We are also exposed to basis risks when a commodity is purchased against one pricing index and sold against a different index. Moreover, we are exposed to some risks that are not hedged, including price risks on product we own, such as pipeline linefill, which must be maintained in order to facilitate transportation of the commodity 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, 2015, we had $20.87 billion in principal amount of consolidated fixed-rate debt outstanding, including current maturities thereof. We also had $1.11 billion of commercial paper notes outstanding at December 31, 2015. Due to the short term nature of commercial paper notes, we view the interest rates charged in connection with these instruments as variable.

Should interest rates increase significantly, the amount of cash required to service our debt (including any future refinancing of our fixed-rate debt instruments) would increase. Additionally, from time to time, we may enter into interest rate swap arrangements, which could increase our exposure to variable interest rates. As a result, significant increases in interest rates could have a material adverse effect on our financial position, results of operations and cash flows.

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

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

The DOT requires pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in HCAs. The majority of the costs to comply with this integrity management rule are associated with pipeline integrity testing and any repairs found to be necessary as a result of such testing. Changes such as advances of in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipe determined to be located in HCAs can have a significant impact on the costs to perform integrity testing and repairs. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Our pipeline facilities are subject to pipeline safety laws and regulations administered by the DOT. These laws and regulations require us to comply with requirements for the design, installation, testing, construction, operation, replacement and management of our pipeline facilities.

In January 2012, President Obama signed the Pipeline Safety Act into law. The Pipeline Safety Act provides, among other things, for additional regulatory oversight of the nation's pipelines, increases the penalties for violations of pipeline safety rules, and complements the DOT's other initiatives. Although many of the requirements under the Pipeline Safety Act, such as the increase in penalties, have been completed, the DOT has not yet issued regulations implementing all of the requirements of the Pipeline Safety Act. These new regulations could increase our operating costs which could have an adverse effect on our results of operations or financial condition. For additional information regarding the pipeline safety regulations and the Pipeline Safety Act, see "Regulatory Matters—Safety Matters—Pipeline Safety" included under Part I, Item 1 and 2 of this annual report.

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

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

Our operations are subject to various environmental, health and safety requirements and potential liabilities under extensive federal, state and local laws and regulations. Further, we cannot ensure that existing environmental, health and safety regulations will not be revised or that new regulations will not be adopted or become applicable to us. Governmental authorities have the power to enforce compliance with applicable regulations and permits and to subject violators to civil and criminal penalties, including substantial fines, injunctions or both. Certain environmental laws, including 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.

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

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

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

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, Item 1 and 2 of this annual report for more information and specific disclosures relating to environmental, health and safety laws and regulations, and costs and liabilities.

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

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

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

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

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

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

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

The FERC uses prescribed rate methodologies for approving regulated tariff rate changes for interstate liquids pipelines. The FERC's indexing methodology currently allows a pipeline to increase its rates by a percentage linked to the PPI. As an alternative to this indexing methodology, we may also choose to support our rates based on a cost-of-service methodology, or by obtaining advance approval to charge "market-based rates," or by charging "settlement rates" agreed to by all affected shippers. These methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates reflecting increased costs. Changes in the FERC's approved methodology for approving rates, or challenges to our application of that methodology, could adversely affect us. Adverse decisions by the FERC in approving our regulated rates could adversely affect our cash flow.

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

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

The Dodd-Frank Wall Street Reform and Consumer Protection Act enacted in 2010 (the "Dodd-Frank Act") provides for new statutory and regulatory requirements for swaps and other derivative transactions, including financial and certain physical oil and gas hedging transactions. Under the Dodd-Frank Act, the CFTC has adopted regulations requiring registration of swap dealers and major swap participants, mandatory clearing of swaps, election of the end-user exception for any uncleared swaps by certain qualified companies, recordkeeping and reporting, business conduct standards and position limits among other requirements. Several of these requirements, including position limits rules, allow the CFTC to impose controls that could have an adverse impact on our ability to hedge risks associated with our business and could increase our working capital requirements to conduct these activities.

Based on an assessment of final rules promulgated by the CFTC, we have determined that we are not a swap dealer, major swap participant or a financial entity, and therefore have determined that we 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. Under the proposed rules, the CFTC would place volumetric limitations on transactions in core referenced futures contracts including NYMEX Henry Hub Natural Gas, Light Sweet Crude Oil, New York Harbor Gasoline Blendstock and New York Harbor Heating Oil along with any contracts which are directly or indirectly linked to the price of a core referenced futures contract. These limits include spot month limits leading up to the close of trading for a particular contract and non-spot month limits which would cover all months combined including the spot month. In the proposed rule, the CFTC has provided certain provisions governing Bona Fide Hedges which would enable the exclusion of certain contracts from the calculation of our positions against a given limit. While we believe that the majority of our hedging transactions would meet one or more of the enumerated categories for Bona Fide Hedges, the rules could have an adverse impact on our ability to hedge certain risks associated with our business and could potentially affect our profitability. In 2014, the CFTC reopened the period for public comment on the newly proposed rules, with the most recent comment period closing on March 25, 2015. As of the filing of this annual report, the CFTC has yet to provide final rules.

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

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

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

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

Risks Relating to Our Partnership Structure

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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 34% 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.

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.

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 substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for 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.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate (which is currently a maximum of 35%) 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 substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the anticipated cash-flow and after-tax return to our unitholders, likely causing a substantial 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 and other forms of taxation. Specifically, we are subject to an entity-level franchise tax on the portion of our income apportioned to Texas. Imposition of any of these taxes in other jurisdictions in which we own assets or conduct business or an increase in the existing tax rates would substantially reduce the cash available for distribution to our unitholders.

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

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

The present 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, the U.S. President and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws including those that affect the tax treatment of certain publicly traded partnerships.

Further, the U.S. Treasury Department and the IRS issued proposed regulations under Section 7704(d)(1)(E) of the Code on May 5, 2015, interpreting the scope of qualifying income for publicly traded partnerships by providing industry-specific guidance with respect to activities that will generate qualifying income for purposes of the qualifying income requirement. The proposed regulations, once issued in final form, may change interpretations of the current law relating to the characterization of income as qualifying income and could modify the amount of our gross income we are able to treat as qualifying income for purposes of the qualifying income requirement.

Any modification to federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to be treated as a partnership for federal income tax purposes (i.e., not taxable as a corporation). We are unable to predict whether any of these changes or any other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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. The U.S. Treasury Department and the IRS recently issued final Treasury Regulations pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders although such tax items must be prorated on a daily basis and the regulations do not specifically authorize the use of the proration method we have adopted. 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.

Recently enacted legislation, applicable to us for taxable years beginning after 2017, alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including penalties and interest) as a result of an audit. Under the new rules, unless we are eligible to, and do, elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed. If we are required to pay taxes, penalties and interest as a result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited tax year.

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

Tax gains or losses on the disposition of our common units could be 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, including depreciation recapture. 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. 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.

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 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 many states, most 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.

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

We will be considered to have technically terminated our existing partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which could result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if certain relief were unavailable, as described below) for one fiscal year and could result in the deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in the unitholder's taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a relief procedure whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to each unitholder for the year notwithstanding two partnership tax years.

A unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of those common units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a common unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

We have adopted certain valuation methodologies in determining 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.

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.

ETP Matter

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

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP $319.4 million in actual damages on March 4, 2014. On July 29, 2014, the court entered judgment against us in an aggregate amount of $535.8 million, which includes (i) $319.4 million as the amount of actual damages awarded by the jury, (ii) an additional $150.0 million in disgorgement for the alleged benefit we received due to a breach of fiduciary duties by us against ETP and (iii) prejudgment interest in the amount of $66.4 million. The court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5%, compounded annually.

We do not believe that the verdict or the judgment entered against us is supported by the evidence or the law. 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. We intend to vigorously oppose the judgment through the appeals process. As of December 31, 2015, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

FTC Matter

On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena *Duces Tecum* from the Federal Trade Commission ("FTC") requesting specified information relating to the Oiltanking acquisition and our operations. On April 13, 2015, we received a Civil Investigative Demand issued by the Attorney General of the State of Texas requesting copies of the same information and any correspondence with the FTC. We are in the process of complying with the requests and are cooperating with the investigations. Based on the limited information that we have at this time, we are unable to predict the outcome of the investigations.

Environmental Matters

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

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

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

For more information regarding our litigation matters, see "Litigation" under Note 17 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report, which subsection is incorporated by reference into this Item 3.

Item 4. *Mine Safety Disclosures*.

Not applicable.

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, 2016, there were approximately 3,300 unitholders of record of our common units. The following table presents high and low sales prices for our common units for the periods presented (as reported by the NYSE Composite ticker tape) and the amount, record date and payment date of the quarterly cash distributions we paid on each of our common units with respect to such periods.

	Price Ranges		Cash Distribution History		
	High	Low	Per Unit	Record Date	Payment Date
2013					
1st Quarter	$30.17	$25.51	$0.3350	04/30/13	05/07/13
2nd Quarter	$31.78	$28.06	$0.3400	07/31/13	08/07/13
3rd Quarter	$32.80	$28.83	$0.3450	10/31/13	11/07/13
4th Quarter	$33.46	$29.57	$0.3500	01/31/14	02/07/14
2014					
1st Quarter	$35.50	$31.51	$0.3550	04/30/14	05/07/14
2nd Quarter	$39.26	$34.52	$0.3600	07/31/14	08/07/14
3rd Quarter	$41.38	$35.55	$0.3650	10/31/14	11/07/14
4th Quarter	$40.95	$30.71	$0.3700	01/30/15	02/06/15
2015					
1st Quarter	$36.98	$30.71	$0.3750	04/30/15	05/07/15
2nd Quarter	$34.73	$29.53	$0.3800	07/31/15	08/07/15
3rd Quarter	$31.17	$22.01	$0.3850	10/30/15	11/06/15
4th Quarter	$29.02	$20.76	$0.3900	01/29/16	02/05/16

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

For additional information regarding our cash distributions to partners, see Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Recent Issuance of Unregistered Securities

There were no sales of unregistered equity securities during 2015.

Common Units Authorized for Issuance Under Equity Compensation Plan

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

Issuer Purchases of Equity Securities

A total of 2,009,970 unit-based awards (e.g., restricted common unit awards granted to key employees of EPCO) vested and were converted to common units during 2015. Of this amount, 683,954 were sold back to us by employees to meet their related tax withholding requirements. The total cost of these repurchased units was $33.6 million. We cancelled such treasury units immediately upon acquisition.

The following table summarizes our repurchase activity during 2015 in connection with these vesting transactions:

Period	Total Number of Units Purchased		Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans	Maximum Number of Units That May Yet Be Purchased Under the Plans
February 2015 (1)	628,750	$	33.68	--	--
May 2015 (2)	33,492	$	34.21	--	--
August 2015 (3)	18,254	$	26.93	--	--
November 2015 (4)	3,458	$	27.47	--	--

(1) Of the 1,852,746 restricted common units that vested in February 2015 and converted to common units, 628,750 units were sold back to us by employees to cover related withholding tax requirements.
(2) Of the 87,298 restricted common units that vested in May 2015 and converted to common units, 33,492 units were sold back to us by employees to cover related withholding tax requirements.
(3) Of the 57,150 restricted common units that vested in August 2015 and converted to common units, 18,254 units were sold back to us by employees to cover related withholding tax requirements.
(4) Of the 12,776 restricted common units that vested in November 2015 and converted to common units, 3,458 units were sold back to us by employees to cover related withholding tax requirements.

In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, could repurchase up to 4,000,000 of our common units on the open market. A total of 2,763,200 common units were repurchased under this program; however, no repurchases have been made since 2002. As of December 31, 2015, we and our affiliates could repurchase up to 1,236,800 additional common units under this program.

Item 6. *Selected Financial Data*.

The following table presents selected historical consolidated financial data of our partnership. This information has been derived from and should be read in conjunction with our audited financial statements included under Part II, Item 8 of this annual report, which presents our audited balance sheets as of December 31, 2015 and 2014 and related statements of consolidated operations, comprehensive income, cash flows and equity for the three years ended December 31, 2015, 2014 and 2013, respectively. As presented in the table, amounts are in millions (except per unit data).

	For the Year Ended December 31,				
	2015	2014	2013	2012	2011
Statements of operations data:					
Total revenues	$ 27,027.9	$ 47,951.2	$ 47,727.0	$ 42,583.1	$ 44,313.0
Cost of sales	19,612.9	40,464.1	40,770.2	36,015.5	38,292.6
Other costs and expenses	4,248.4	3,970.9	3,656.8	3,522.7	3,207.7
Equity in income of unconsolidated affiliates	373.6	259.5	167.3	64.3	46.4
Operating income	3,540.2	3,775.7	3,467.3	3,109.2	2,859.1
Interest expense	961.8	921.0	802.5	771.8	744.1
Net income	2,558.4	2,833.5	2,607.1	2,428.0	2,088.3
Net income attributable to noncontrolling interests	37.2	46.1	10.2	8.1	41.4
Net income attributable to limited partners	2,521.2	2,787.4	2,596.9	2,419.9	2,046.9
Earnings per unit:					
Basic ($/unit)	1.28	1.51	1.45	1.40	1.24
Diluted ($/unit)	1.26	1.47	1.41	1.35	1.19
Cash distributions paid with respect to period ($/unit)	1.5300	1.4500	1.3700	1.2863	1.2176

	As of December 31,				
	2015	2014	2013	2012	2011
Balance sheet data:					
Property, plant and equipment, net	$ 32,034.7	$ 29,881.6	$ 26,946.6	$ 24,846.4	$ 22,191.6
Investments in unconsolidated affiliates	2,628.5	3,042.0	2,437.1	1,394.6	1,859.6
Total assets	48,952.0	47,201.0	40,138.7	35,934.4	34,125.1
Long-term debt, including current maturities thereof	22,690.6	21,363.8	17,351.5	16,201.8	14,529.4
Total liabilities	28,450.9	27,508.8	24,698.3	22,638.4	21,905.8
Equity:					
Partners' equity	$ 20,295.1	$ 18,063.2	$ 15,214.8	$ 13,187.7	$ 12,113.4
Noncontrolling interests	206.0	1,629.0	225.6	108.3	105.9
Total equity	$ 20,501.1	$ 19,692.2	$ 15,440.4	$ 13,296.0	$ 12,219.3
Limited partner units outstanding (millions)	2,012.6	1,937.3	1,871.4	1,797.6	1,763.2

General Discussion of Our Selected Financial Data Since 2011

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

The domestic oil and gas industry experienced rapid growth over the last few years due to advances in unconventional production methods such as hydraulic fracturing and horizontal drilling, which have had a significant impact on hydrocarbon resource basins such as the Eagle Ford Shale in South Texas, Permian Basin in West Texas and the Rocky Mountains region. Production growth has translated into increased demand by crude oil and natural gas producers for the midstream energy services that we provide. Our results of operations over the last five years reflects this increase in demand, which we have supported through the construction of new midstream assets. As growth capital projects are completed and commence operations, they contribute additional sources of cash flow to our operating results.

Property, plant and equipment balances increased since 2011 due to our capital spending program, which includes business acquisitions such as EFS Midstream in 2015 and Oiltanking in 2014. For information regarding our capital spending, see "Capital Spending" included under Part II, Item 7 of this annual report.

Investments in unconsolidated affiliates decreased in 2015 primarily due to the sale of our Offshore Business, which included a number of pipeline and platform joint ventures operating in the Gulf of Mexico. Excluding this divestiture, our investments in unconsolidated affiliates increased since 2012 as a result of cash contributions we made to fund the major capital projects of several investees (e.g., construction of the Texas Express Pipeline, Front Range Pipeline and the Seaway Loop). Investments in unconsolidated affiliates decreased in 2011 and 2012 primarily due to the liquidation of our equity investment in ETP.

Our debt balances, including related interest expense, have increased since 2011 primarily due to the funding of a portion of our capital spending program using borrowings under bank credit agreements and the issuance of senior notes.

Our equity balances, along with the related number of common units outstanding, have increased over time due to the issuance of units in connection with business combinations and the sale of units under our "at-the-market" program, distribution reinvestment plan, employee unit purchase plan and underwritten offerings. Proceeds generated from the sale of common units were primarily used to fund a portion of our capital spending program.

Additional information regarding our results of operations, liquidity and capital resources and capital spending can be found under Part II, Item 7 of this annual report.

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

For the Years Ended December 31, 2015, 2014 and 2013

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

Key References Used in this Management's Discussion and Analysis

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

The membership interests of Dan Duncan LLC are owned by a voting trust, the current trustees ("DD LLC Trustees") of which are: (i) Randa Duncan Williams, who is also a director and Chairman of the Board of 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. 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 President 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 Administrative Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 33.6% of our limited partner interests at December 31, 2015.

References to "Oiltanking" and "Oiltanking GP" mean Oiltanking Partners, L.P. and OTLP GP, LLC, the general partner of Oiltanking, respectively. In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking, all of the member interests of Oiltanking GP and the incentive distribution rights ("IDRs") held by Oiltanking GP from Oiltanking Holding Americas, Inc. ("OTA") 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.

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company ("Pioneer") and Reliance Industries Limited ("Reliance").

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, 2015 (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," "believe," "may," "potential" and similar expressions and statements regarding our plans and objectives for future operations are intended to identify forward-looking statements. Although we and our general partner believe that our expectations reflected in such forward-looking statements are reasonable, neither we nor our general partner can give any assurances that such expectations will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions as described in more detail under Part I, Item 1A of this annual report. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this annual report speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason.

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 midstream energy operations currently include: natural gas gathering, treating, processing, transportation and storage; NGL transportation, fractionation, storage, and import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; petrochemical and refined products transportation, storage and terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets currently include approximately 49,000 miles of pipelines; 250 MMBbls of storage capacity for NGLs, crude oil, petrochemicals and refined products; and 14 Bcf of natural gas storage capacity.

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

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & 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.

On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015.

Each of our remaining 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.

Significant Recent Developments

Enterprise Management to Recommend 5.2% Distribution Growth for 2016
In January 2016, our management announced plans to recommend to the Board of Enterprise GP cash distributions totaling $1.61 per unit with respect to 2016, which, if approved by the Board, would represent a 5.2% increase compared to a total of $1.53 per unit of distributions declared with respect to calendar year 2015. The recommended quarterly cash distributions for 2016 would be as follows (with respect to each quarter presented): $0.395, first quarter; $0.400, second quarter; $0.405, third quarter; and $0.410, fourth quarter. Historically, it has been our practice to not provide guidance with respect to distribution growth; however, due to recent actions by some of our midstream peers to reduce or freeze their dividends/distributions, we believe it is important to provide our investors with visibility into management's planned recommendations for our distribution growth for 2016 based on current expectations.

Enterprise Among First Companies to Export U.S. Crude Oil
In December 2015, the U.S. government lifted its 40-year ban on exports of domestically produced crude oil. As a result of this recent change in law, we provided pipeline and marine terminal services at our Houston Ship Channel facility in January 2016 to load an export cargo of 600 thousand barrels of domestic light crude oil. We believe that removal of the crude oil export ban facilitates economic growth and job creation for the United States as well as enhances our national and energy security. This action also provides new markets to domestic producers, especially producers of light crude oil, and the global markets with supply diversification.

Completion of Expansion Projects at our Houston Ship Channel LPG Export Terminal
In December 2015, we completed the final phase of an expansion project at our Houston Ship Channel LPG Export Terminal that increased its loading capability from 9.0 MMBbls per month to 16.0 MMBbls per month. Our maximum loading capacity at this marine terminal is now approximately 27,500 barrels per hour.

The expansion of our Houston Ship Channel LPG Export Terminal is supported by long-term LPG sales agreements with exporters. In November 2015, we announced the execution of additional long-term contracts with customers to export a total of approximately 125 MMBbls of LPG over a seven-year period from this terminal. Including the volume associated with these additional agreements, our Houston Ship Channel facility is now over 90% subscribed, in terms of estimated operating capacity, through 2019. Furthermore, a majority of the terminal's operating capacity is under contract extending into 2022.

Completion of Aegis Ethane Pipeline
In December 2015, we completed the remaining 162-mile segment of the Aegis Ethane Pipeline ("Aegis") from Lake Charles, Louisiana to Napoleonville, Louisiana. This new 162-mile segment, along with the 108 miles of Aegis previously placed into service, provides reliable ethane supplies to petrochemical facilities between Mont Belvieu, Texas and the Mississippi River in Louisiana. When combined with our South Texas NGL Pipeline System, Aegis provides shippers with access to an ethane header system stretching approximately 500 miles between Corpus Christi, Texas and the Mississippi River in Louisiana. Aegis is supported by customer commitments in excess of 360 MBPD that ramp up over the next four years.

Sale of Offshore Business
On July 24, 2015, we completed the sale of our Offshore Business to Genesis, which primarily consisted of our Offshore Pipelines & Services business segment, for approximately $1.53 billion in cash. The Offshore Business served drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama and included approximately 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms. Our results of operations reflect ownership of the Offshore Business through July 24, 2015.

We viewed the Offshore Business as an extension of our midstream energy services network. As such, sale of these assets did not represent a strategic shift in our consolidated operations, and their sale does not have a major effect on our financial results. The sale of this non-strategic business allowed us to redeploy capital to other business opportunities that we believe will generate a higher rate of return for us in the future. Also, proceeds from this sale reduced our need to issue additional equity and debt to support our ongoing capital spending program.

For additional information regarding this sale, see Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Expansion of Propylene Pipeline System

In July 2015, we announced a series of projects to convert and expand segments of our petrochemicals pipeline network in order to increase throughput capacity for polymer grade propylene ("PGP") and enhance system flexibility and reliability.

- *North Dean pipeline conversion and expansion* – The 149-mile pipeline will be converted from refinery grade propylene ("RGP") service to PGP service. The conversion is scheduled for completion in January 2017. Originating at our Mont Belvieu, Texas complex, the converted pipeline will serve petrochemical facilities as far south as Seadrift, Texas in Calhoun County. Construction of a 33-mile lateral pipeline, new metering stations and additional pumping capacity will accommodate the additional volumes and increase total PGP delivery capacity to more than 150 MBPD.

- *Lou-Tex propylene pipeline conversion* – The 263-mile, bi-directional pipeline, which currently transports chemical grade propylene between Sorrento, Louisiana and Mont Belvieu, Texas will be converted to PGP service. The conversion is scheduled for completion in 2020.

- *RGP pipeline and rail terminal expansion* – Construction of a new 65-mile, 10-inch diameter pipeline, which will transport RGP between Sorrento and Breaux Bridge, Louisiana, is scheduled for completion in early 2017. Rail receipt facilities at Mont Belvieu are also being expanded to give us the capability to unload up to 80 RGP rail cars per day.

We currently have six propylene fractionation units at our Mont Belvieu complex. Following completion of the new propane dehydrogenation ("PDH") plant, we will have the capability to produce 8 billion pounds of PGP annually at our Mont Belvieu complex. In addition, a portion of our salt dome storage capacity in Mont Belvieu is dedicated to PGP service.

Acquisition of Eagle Ford Midstream Assets

In July 2015, we purchased EFS Midstream from affiliates of Pioneer and Reliance for approximately $2.1 billion. The purchase price will be paid in two installments. The first installment of approximately $1.1 billion was paid at closing on July 8, 2015 and the final installment of approximately $1.0 billion will be paid no later than the first anniversary of the closing date. The effective date of the acquisition was July 1, 2015.

The EFS Midstream System provides condensate gathering and processing services as well as gathering, treating and compression services for the associated natural gas. The EFS Midstream System includes approximately 460 miles of gathering pipelines, ten central gathering plants, 119 MBPD of condensate stabilization capacity and 780 MMcf/d of associated natural gas treating capacity. Our primary purpose in acquiring the EFS Midstream System was to secure the underlying production, particularly condensate, for our midstream asset network. Under terms of the associated agreements, Pioneer and Reliance have dedicated certain of their Eagle Ford Shale acreage to us under 20-year, fixed-fee gathering agreements that include minimum volume requirement for the first seven years. Pioneer and Reliance have also entered into related 20-year fee-based agreements with us for natural gas transportation and processing, NGL transportation and fractionation, and for condensate and crude oil transportation services.

In connection with the agreements to acquire EFS Midstream, we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for Pioneer and Reliance, if requested by these 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.

For additional information regarding our acquisition of EFS Midstream, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Plans to Construct Crude Oil and Condensate Pipeline from Midland to Sealy, Texas
In April 2015, we announced the execution of long-term agreements that support development of a new 24-inch diameter pipeline (the "Midland-to-Sealy" pipeline) that would transport increasing volumes of crude oil and condensate from the Permian Basin to markets in southeast Texas. The new pipeline will originate at our Midland, Texas crude oil terminal and extend 416 miles to our Sealy, Texas storage facility. Volumes arriving at Sealy would then be transported to our ECHO terminal using our Rancho II pipeline. Using the ECHO terminal, shippers will have direct access to every refinery in Houston, Texas City, Beaumont and Port Arthur, as well as our dock facilities. The Midland-to-Sealy pipeline is expected to have an initial transportation capacity of 300 MBPD and is expandable up to 450 MBPD. Committed shippers on the pipeline recently requested to extend the construction timeline by up to one year, and we are currently evaluating our ability to accommodate their needs. The pipeline was originally scheduled to commence operations in mid-2017.

Plans to Construct Natural Gas Processing Facility in Delaware Basin
In April 2015, we formed a joint venture with an affiliate of Occidental Petroleum Corporation to develop a new 150 MMcf/d cryogenic natural gas processing facility that will accommodate growing production of NGL-rich natural gas from the Delaware Basin. The facility is supported by long-term, firm contracts and is expected to begin operations in mid-2016. We serve as construction manager for the project and will serve as operator once the new facility commences operations. The new facility is located in Reeves County, Texas.

Formation of Panola Pipeline Joint Venture
In February 2015, we formed a joint venture involving our Panola Pipeline with affiliates of Anadarko Petroleum Corporation ("Anadarko"), DCP Midstream Partners, LP ("DCP") and MarkWest Energy Partners, L.P. ("MarkWest"). We will continue to serve as operator of the Panola Pipeline and own 55% of the member interests in the joint venture. Affiliates of Anadarko, DCP and MarkWest will own the remaining 45% member interests, with each holding a 15% interest.

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

Completion of Oiltanking Acquisition
In October 2014, we completed the first step ("Step 1") of a two-step acquisition of Oiltanking by paying approximately $4.41 billion to OTA for Oiltanking GP, the related IDRs and approximately 65.9% of the limited partner interests of Oiltanking. As a second step ("Step 2") of the Oiltanking acquisition (separately negotiated by the conflicts committee of Oiltanking GP on behalf of Oiltanking), we entered into an Agreement and Plan of Merger (the "merger agreement") with Oiltanking in November 2014 that provided for the following:

- the merger of a wholly owned subsidiary of ours with and into Oiltanking, with Oiltanking surviving the merger as our wholly owned subsidiary; and

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

In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including our ownership interests) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,517 of our common units were issued to Oiltanking's former public unitholders. With the completion of Step 2, total consideration paid by us for Oiltanking was approximately $6.02 billion.

On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena *Duces Tecum* from the Federal Trade Commission ("FTC") requesting specified information relating to the Oiltanking acquisition and Enterprise's operations. On April 13, 2015, we received a Civil Investigative Demand issued by the Attorney General of the State of Texas requesting copies of the same information and any correspondence with the FTC. We are in the process of complying with the requests and are cooperating with the investigations. Based on the limited information that we have at this time, we are unable to predict the outcome of the investigations.

For additional information regarding the Oiltanking acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

General Outlook for 2016

Commercial Outlook

Supply Side Observations

As a result of significant advances in non-conventional drilling and production technology, North American reserves and production of hydrocarbons, primarily from shale resource basins such as the Eagle Ford in South Texas, the Permian Basin in West Texas and the Appalachia Basin in the Northeast U.S., increased substantially in recent years. The increase in U.S. hydrocarbon supplies led to a reduction in imports of crude oil, NGLs, refined products and natural gas into the U.S. Conversely, this trend has resulted in significant increases in hydrocarbon exports from the U.S., particularly of refined products and LPGs. In light of a weaker global economic outlook (especially for Europe and China) and in the face of increasing production from North America and certain countries in the Middle East and Africa, global production and inventories of hydrocarbons (particularly crude oil) began to exceed demand in 2014. In response to the growing supplies, beginning in November 2014, the Organization of Petroleum Exporting Countries, or OPEC, opted to defend its market share by maintaining (and in some cases increasing) its crude oil production levels. The result has been a dramatic decline in global crude oil prices from an average of approximately $93 per barrel in 2014 to $49 per barrel in 2015, as measured by the price of West Texas Intermediate ("WTI"). As a result of excess domestic supplies, natural gas prices also experienced a significant year-to-year decline from an average of approximately $4.43 per MMBtu in 2014 to $2.67 per MMBtu in 2015, as measured at Henry Hub. In response to lower energy commodity prices, domestic producers began to reduce their drilling activity in 2015; however, because of the lagging effect of production to drilling activity, average crude oil production for 2015 is estimated to have increased by approximately 700 MBPD when compared to 2014.

WTI prices declined further in January 2016, averaging $32 per barrel. In early February 2016, the International Energy Agency ("IEA") reported that crude oil inventories in developed nations increased counter-seasonally in December 2015 by 7.6 MMBbls to 3 billion barrels, which is approximately 350 MMBbls above average. The IEA recently estimated that global crude oil supplies for the first half of 2016 may exceed demand by approximately 1.5 MMBPD. In reaction to this period of low energy prices and high inventories, the debt ratings agencies Moody's Investor Service ("Moody's") and Standard & Poor's ("Standard & Poor's) announced downgrades and/or negative credit outlooks for many oil and gas producers, oilfield service companies and midstream companies. In January 2016, Moody's placed 120 energy companies on review for a possible downgrade as Moody's saw substantial risk that crude oil prices may recover much more slowly over the medium term than many companies expect, as well as a risk that prices might fall further. We have not been included in any of these actions and changes in outlooks.

Many producers have announced additional reductions in drilling activity in 2016 to preserve their cash flow, financial position and liquidity. At the beginning of February 2016, the U.S. oil and gas rig count as measured by Baker Hughes dropped to 571 rigs, the lowest level since June 1999. Per Baker Hughes, rig counts in substantially all of the major shale and non-conventional basins are either at new near term lows or matching previous lows. While the rate of hydrocarbon production growth has slowed due to low prices, the domestic crude oil and natural gas industry has been able to significantly reduce drilling and completion costs through continued improvements in technology and more efficient processes, including focusing on only the best drilling locations. Most forecasters predict that production of oil and gas in the U.S. could decline in the range of 5% to 10% during 2016, but, in general, we do not expect drastic reductions in overall U.S production levels in 2016 in spite of the low price environment. However, certain regions such as the Eagle Ford, Bakken and Mid-Continent areas may see crude oil and condensate production declines of 10% to 20% in 2016. With respect to natural gas, certain regions such as the Barnett, Fayetteville, Mid-Continent, Haynesville, Rockies and Eagle Ford areas may experience production declines from 5% to 15%. As a result, we expect certain of our assets in the Eagle Ford, Rockies and Haynesville areas to be impacted by lower volumes in 2016.

Due to lower global energy prices, indications are that plans for longer lead time, capital intensive projects are being delayed or in many instances cancelled as exploration and production companies shift their focus to shorter lead time and less risky projects. We believe that U.S. shale resource basins favor this low risk, short lead time production profile, and that U.S. shale producers will continue to play an increasing role in both domestic and global markets as markets begin to stabilize because of their cost competitiveness, lower capital commitments before production and flexibility. These attributes lead certain energy experts to believe U.S. shale production is now the world's swing crude oil supply that would influence global crude oil prices at the margin and keep prices range bound.

Long-term, we believe that production basins located closest to prime markets such as the U.S. Gulf Coast petrochemical and refining complex (e.g., the Eagle Ford Shale and Permian Basin regions) will continue to be preferred by producers due to more favorable economics as compared to other more distant areas (mostly due to reduced transportation costs).

In contrast to the negative impacts on energy producers, lower energy commodity prices have led to an increase in energy consumption by individual consumers, particularly for gasoline, and by energy intensive industries (e.g., steel manufacturing and petrochemicals) as lower energy and feedstock costs reduce the operating costs for such businesses and in some instances make them more globally competitive. We believe that an increase in demand for crude oil, natural gas and NGLs from these types of industries, along with other positive consumer-driven demand responses to the lower prices, may begin to balance crude oil supply and demand fundamentals by the end of 2016. Regardless of such market dynamics, almost all of the major assets we have under construction or have recently completed, whether supply or demand oriented, are supported by long-term fee-based commitments from producers, shippers and/or end-use customers. For additional information regarding our recent significant projects, see "Significant Recent Developments" within this Part II, Item 7.

Demand Side Opportunities

In recent years, natural gas and NGLs developed a feedstock price advantage over more costly crude oil derivatives (such as naphtha). In general, we expect this trend to continue due to: (i) ongoing production from domestic shale resource plays and efforts by producers to lower associated drilling costs; (ii) anticipated long-term increases in demand for crude oil by developing economies; and (iii) geopolitical risks in many areas of the world that are major exporters of crude oil, which may cause unexpected crude oil price increases. This price advantage lends itself to a variety of demand-side opportunities, including higher demand from the U.S. petrochemical industry and increased exports of various hydrocarbons (e.g., LPG, ethane and crude oil).

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

- Chevron Phillips Chemical Co. announced in December 2011 that it expects to build a 1.5 million metric tons per year ethylene plant in Cedar Bayou, Texas by 2017;

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

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

- Sasol Ltd. announced in October 2014 that it had reached final approval to build a 1.5 million metric ton per year ethylene and derivatives plant in Lake Charles, Louisiana, expected to be completed by 2017;

- Axiall Corporation and Lotte Chemical Corporation announced in December 2015 that they have finalized joint-venture arrangements to construct an ethane cracker in Lake Charles, Louisiana with expected completion in early 2019; and

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

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

Based on industry publications, domestic production of ethylene in 2015 was estimated to be 155 million pounds per day compared to 146 million pounds per day in 2014. Ethane is the most widely used feedstock by the U.S. petrochemical industry in the production of ethylene. As a result, ethane consumption by domestic petrochemical companies has, at times, been in excess of 1.1 MMBPD. We believe the U.S. ethylene industry could consume approximately 200 MBPD of additional ethane feedstocks over the next few years through modifications, debottlenecking and expansions at existing facilities. In addition, we believe that announced new petrochemical plant construction projects, including those noted in the preceding paragraph, could consume well over 900 MBPD of additional ethane feedstocks when completed. However, ethane production capacity continues to be significantly in excess of the ethylene industry's ability to consume ethane, resulting in significant volumes of ethane not being extracted from the natural gas stream by producers and natural gas processors in an effort to balance ethane supply to demand. In the absence of additional near-term demand growth or a significant drop in production, we expect ethane to remain oversupplied. This oversupply could lower the value of our equity NGL production and reduce the volumes that would otherwise be handled by our downstream NGL fractionators and pipelines.

U.S. exports of fully refrigerated LPG continue to increase as a result of ample domestic production, increased export capacity and competitive, transparent pricing when compared to international markets. Overall, U.S. propane waterborne exports increased from approximately 390 MBPD in 2014 to 615 MBPD in 2015. Markets in Central and South America have been the major source of new demand for U.S. LPG exports; however, volumes are also being transported to Northwest Europe and the Far East. LPG exports from the U.S. Gulf Coast to Central and South America are expected to increase in the future as these economies continue to develop. Furthermore, we expect that increased volumes of Gulf Coast-sourced LPGs will be exported in the coming years to Asian markets due to growth of these economies and completion of the Panama Canal expansion, which is anticipated in 2016. In anticipation of the aforementioned growth in LPG exports, we recently completed the final phase of an expansion project at our Houston Ship Channel LPG Export Terminal that increased its loading rate for LPG (nameplate capacity) to approximately 27,500 barrels per hour.

In addition to LPG, we expect that exports of domestically produced ethane will increase in the coming years. We estimate that U.S. ethane production capacity currently exceeds U.S. demand by 500 MBPD to 600 MBPD and could exceed demand by up to 700 MBPD by 2020, after considering the estimated incremental demand from new third party ethylene facilities that have been announced for the Gulf Coast. Our Houston Ship Channel ethane export facility, which we expect to place into service in the third quarter of 2016, will provide producers with access to international markets for domestically-produced ethane, and will assist U.S. producers in increasing (or maintaining) their associated production of natural gas, condensate and crude oil. When completed, our ethane export facility is expected to have an aggregate loading rate (nameplate capacity) of approximately 10,000 barrels per hour and will be integrated with our Mont Belvieu NGL fractionation and storage complex. Up to now, U.S. ethane exports were generally limited to petrochemical customers in Canada that could receive volumes by pipeline.

We believe that as U.S. supply and demand for natural gas and ethane becomes more balanced through exports and incremental demand from ethylene facilities that natural gas and ethane prices will stabilize and increase. Supply basins with dry natural gas and some of the lowest development costs in the U.S. such as the Haynesville/Bossier, Barnett, Fayetteville, Piceance and Jonah/Pinedale shales could experience an increase in drilling activity to maintain, and potentially increase, their future production levels. The Haynesville resource basin is an excellent example of a dry gas area that could experience substantial increase in drilling activity as liquefied natural gas exports and industrial demand from the U.S. Gulf Coast increase over the next few years.

In December 2015, the U.S. government completely lifted its ban on exporting domestically produced crude oil, and we believe that this should be beneficial to the domestic crude oil and natural gas industry in general and to us in particular. Our assets are strategically located on the U.S. Gulf Coast where we could see simultaneous imports and exports of various grades of crude oil as refineries optimize their crude oil input slate, trading companies import and export different grades of crude oil depending on global and regional supply-demand factors, and producers optimize their production depending on market price signals. With significant crude oil export capabilities at Freeport, Texas City, in the Houston Ship Channel and at Beaumont, Texas, lifting of the export ban should have a beneficial impact on our crude oil pipeline, storage and dock assets (without any significant expenditure). However, this outlook could be muted if there is a prolonged reduction in domestic crude oil drilling and production, or if overseas crude markets become significantly discounted compared to the U.S. Gulf Coast for an extended period.

Liquidity Outlook

Debt and equity prices for the energy sector, including those companies with investment grade credit ratings, has decreased significantly since mid-2014. This has generally impacted both the cost of capital and access to capital. Throughout 2015, the corporate debt and equity capital markets were accessible to us, along with adequate credit availability from banks. At December 31, 2015, we had $4.4 billion of consolidated liquidity, which was comprised of $4.38 billion of available borrowing capacity under EPO's revolving credit facilities and $19.0 million of unrestricted cash on hand. 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, access to capital markets and access to bank capital to fund our capital expenditures and working capital needs for the reasonably foreseeable future.

In February 2016, we repaid EPO's $750 million Senior Notes AA using available cash, borrowings under our Multi-Year Revolving Credit Facility and proceeds from the issuance of short-term notes under our commercial paper program. We do not have any other senior note obligations maturing in 2016. Our next maturing series of senior notes (in the aggregate principal amount of $800 million) are due in September 2017.

The U.S. government is expected to continue to run substantial annual budget deficits in the coming years that will require a corresponding issuance of debt by the U.S. Treasury. The interest rate on U.S. Treasury debt has a direct impact on the cost of our debt. At this time, we are uncertain what impact the expected large issuances of U.S. Treasury debt and the prevailing economic and capital market conditions during these future periods will have on the cost and availability of capital, and we have not executed any forward starting interest rate swaps to hedge a portion of our expected future debt issuances in connection with the refinancing of debt. We continue to monitor and evaluate the condition of the capital markets and our interest rate risk with respect to funding our capital spending program and refinancing upcoming maturities.

Results of Operations

Summarized Consolidated Income Statement Data

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

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Revenues	$ 27,027.9	$ 47,951.2	$ 47,727.0
Costs and expenses:			
Operating costs and expenses:			
Cost of sales	19,612.9	40,464.1	40,770.2
Other operating costs and expenses	2,449.4	2,541.8	2,310.4
Depreciation, amortization and accretion expenses	1,428.2	1,282.7	1,148.9
Net losses (gains) attributable to asset sales and insurance recoveries	15.6	(102.1)	(83.4)
Non-cash asset impairment charges	162.6	34.0	92.6
Total operating costs and expenses	23,668.7	44,220.5	44,238.7
General and administrative costs	192.6	214.5	188.3
Total costs and expenses	23,861.3	44,435.0	44,427.0
Equity in income of unconsolidated affiliates	373.6	259.5	167.3
Operating income	3,540.2	3,775.7	3,467.3
Interest expense	(961.8)	(921.0)	(802.5)
Change in fair value of Liquidity Option Agreement	(25.4)	--	--
Other, net	2.9	1.9	(0.2)
Benefit from (provision for) income taxes	2.5	(23.1)	(57.5)
Net income	2,558.4	2,833.5	2,607.1
Net income attributable to noncontrolling interests	(37.2)	(46.1)	(10.2)
Net income attributable to limited partners	$ 2,521.2	$ 2,787.4	$ 2,596.9

Consolidated Revenues

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

	For the Year Ended December 31,		
	2015	**2014**	**2013**
NGL Pipelines & Services:			
Sales of NGLs and related products	$ 8,044.8	$ 15,460.1	$ 15,916.0
Midstream services	1,743.2	1,629.7	1,204.2
Total	9,788.0	17,089.8	17,120.2
Crude Oil Pipelines & Services:			
Sales of crude oil	9,732.9	19,783.9	20,371.3
Midstream services	573.0	400.4	279.1
Total	10,305.9	20,184.3	20,650.4
Natural Gas Pipelines & Services:			
Sales of natural gas	1,722.6	3,181.7	2,571.6
Midstream services	1,020.7	1,022.1	966.9
Total	2,743.3	4,203.8	3,538.5
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	3,333.5	5,575.5	5,568.8
Midstream services	778.4	741.0	689.7
Total	4,111.9	6,316.5	6,258.5
Offshore Pipelines & Services:			
Sales of natural gas	--	0.3	0.5
Sales of crude oil	3.2	8.6	5.7
Midstream services	75.6	147.9	153.2
Total	78.8	156.8	159.4
Total consolidated revenues	$ 27,027.9	$ 47,951.2	$ 47,727.0

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 2015 was Shell Oil Company and its affiliates (collectively, "Shell"), which accounted for 7.4% of our consolidated revenues. The following table presents our consolidated revenues from Shell by business segment for the year ended December 31, 2015 (dollars in millions):

NGL Pipelines & Services	$ 400.4
Crude Oil Pipelines & Services	1,335.8
Natural Gas Pipelines & Services	48.6
Petrochemical & Refined Products Services	206.5
Offshore Pipelines & Services	8.0
Total	$ 1,999.3

Selected Energy Commodity Price Data

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

	Natural Gas, $/MMBtu	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	PGP, $/pound	RGP, $/pound	WTI Crude Oil, $/barrel	LLS Crude Oil, $/barrel
	(1)	(2)	(2)	(2)	(2)	(2)	(3)	(3)	(4)	(4)
2013 Averages	$3.65	$0.26	$1.00	$1.39	$1.43	$2.13	$0.69	$0.58	$97.97	$107.34
2014 by quarter:										
1st Quarter	$4.95	$0.34	$1.30	$1.39	$1.42	$2.12	$0.73	$0.61	$98.68	$104.43
2nd Quarter	$4.68	$0.29	$1.06	$1.25	$1.30	$2.21	$0.70	$0.57	$102.99	$105.55
3rd Quarter	$4.07	$0.24	$1.04	$1.25	$1.28	$2.11	$0.71	$0.58	$97.21	$100.94
4th Quarter	$4.04	$0.21	$0.76	$0.98	$0.99	$1.49	$0.69	$0.52	$73.15	$76.08
2014 Averages	$4.43	$0.27	$1.04	$1.22	$1.25	$1.98	$0.71	$0.57	$93.01	$96.75
2015 by quarter:										
1st Quarter	$2.99	$0.19	$0.53	$0.68	$0.68	$1.10	$0.50	$0.37	$48.63	$52.83
2nd Quarter	$2.65	$0.18	$0.46	$0.59	$0.60	$1.26	$0.42	$0.29	$57.94	$62.97
3rd Quarter	$2.77	$0.19	$0.40	$0.55	$0.55	$0.98	$0.33	$0.21	$46.43	$50.17
4th Quarter	$2.27	$0.18	$0.42	$0.60	$0.61	$0.97	$0.31	$0.18	$42.18	$43.54
2015 Averages	$2.67	$0.18	$0.45	$0.61	$0.61	$1.08	$0.39	$0.26	$48.80	$52.38

(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) PGP prices represent average contract pricing for such product as reported by Chemical Market Associates, Inc. ("CMAI"). RGP prices represent weighted-average spot prices for such product as reported by CMAI.

(4) Crude oil prices are based on commercial index prices for WTI as measured on the New York Mercantile Exchange ("NYMEX") and for LLS 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. Crude oil, natural gas and NGL prices have been depressed since the fourth quarter of 2014 primarily due to an oversupply of these commodities on world markets. The weighted-average indicative market price for NGLs was $0.49 per gallon in 2015 versus $0.97 per gallon in 2014 and $1.02 per gallon in 2013.

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

We attempt to mitigate any commodity price exposure through our hedging activities as well as through converting keepwhole and similar contracts to fee-based arrangements. See 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.

Consolidated Income Statement Highlights

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

Comparison of 2015 with 2014

Revenues

Total revenues for 2015 decreased $20.92 billion when compared to total revenues for 2014. Revenues from the marketing of crude oil and natural gas decreased $11.52 billion year-to-year primarily due to lower sales prices, which accounted for a $10.43 billion decrease, and lower sales volumes, which accounted for an additional $1.09 billion decrease. Revenues from the marketing of NGLs and refined products decreased a net $8.13 billion year-to-year primarily due to lower sales prices, which accounted for an $8.81 billion decrease, partially offset by higher sales volumes, which accounted for a $680.8 million increase. Revenues from the marketing of petrochemicals, octane additives and high purity isobutylene ("HPIB") decreased $1.49 billion year-to-year attributable to lower sales prices.

Revenues from midstream services increased a net $249.8 million year-to-year primarily due to the ongoing expansion of our operations. Revenues increased $163.4 million year-to-year due to the timing of our acquisition of Oiltanking. Revenues for 2015 include $117.8 million from assets we acquired in connection with the EFS Midstream acquisition. Revenues decreased $72.6 million year-to-year primarily due to the sale of our Offshore Business in July 2015. The remaining $41.2 million year-to-year increase in revenues is primarily due to recently completed assets such as the ATEX pipeline, portions of Aegis and expanded crude oil storage capacity at our ECHO terminal.

Operating costs and expenses

Total operating costs and expenses for 2015 decreased $20.55 billion when compared to total operating costs and expenses for 2014. The cost of sales associated with our marketing of crude oil and natural gas decreased $11.05 billion year-to-year primarily due to lower purchase prices, which accounted for a $10.02 billion decrease, and lower sales volumes, which accounted for an additional $1.03 billion decrease. The cost of sales associated with our marketing of NGLs and refined products decreased a net $8.13 billion year-to-year primarily due to lower purchase prices, which accounted for an $8.78 billion decrease, partially offset by higher sales volumes, which accounted for a $651.3 million increase. The cost of sales associated with our marketing of petrochemicals, octane additives and HPIB decreased $1.64 billion year-to-year attributable to lower purchase prices.

Other operating costs and expenses decreased a net $92.4 million year-to-year due in part to (i) lower fuel costs, which accounted for a $73.9 million decrease, (ii) a producer settlement involving our San Juan Gathering System in 2014, which accounted for an $18.0 million decrease and (iii) the sale of our Offshore Business in July 2015, which primarily accounted for an additional $25.2 million year-to-year decrease. These decreases were partially offset by the addition of $49.3 million in operating costs attributable to the timing of the Oiltanking acquisition and assets we acquired in the EFS Midstream acquisition.

Depreciation, amortization and accretion expenses in operating costs and expenses increased $145.5 million in 2015 when compared to 2014 primarily due to the Oiltanking and EFS Midstream acquisitions, which collectively accounted for $115.7 million of the year-to-year increase. Accretion expense for 2015 includes $39.5 million recognized for certain asset retirement obligations of our former Offshore Business. For information regarding our asset retirement obligations, see Note 5 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

We recorded net losses within operating costs and expenses of $15.6 million attributable to asset sales and insurance recoveries in 2015 compared to net gains of $102.1 million in 2014. In 2015, we recognized a $12.3 million loss attributable to our sale of the Offshore Business. In 2014, we recognized $95.0 million of gains attributable to the receipt of nonrefundable cash insurance proceeds. These proceeds were attributable to property damage claims we filed in connection with the February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility.

Operating costs and expenses also include $162.6 million and $34.0 million of non-cash asset impairment charges for the years ended December 31, 2015 and 2014, respectively. We recorded a $54.8 million non-cash asset impairment charge for 2015 in connection with the sale of our Offshore Business. The remainder of our non-cash asset impairment charges for 2015 primarily relate to natural gas processing assets in southern Louisiana, certain marine vessels and the abandonment of certain crude oil and natural gas pipeline assets in Texas.

General and administrative costs

General and administrative costs for 2015 decreased $21.9 million when compared to 2014 primarily due to lower employee compensation costs, which accounted for a $14.8 million decrease. In addition, general and administrative costs for 2014 included $3.8 million of transaction costs associated with Step 1 of the Oiltanking acquisition and $4.7 million of expense for the settlement of litigation associated with our merger in 2010 with Enterprise GP Holdings L.P.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates increased $114.1 million in 2015 when compared to 2014 primarily due to increased earnings from our investments in crude oil and NGL pipeline joint ventures.

Interest expense

Interest expense for 2015 increased $40.8 million when compared to 2014. The following table presents the components of our consolidated interest expense for the years indicated (dollars in millions):

	For the Year Ended December 31,	
	2015	**2014**
Interest charged on debt principal outstanding	$ 1,063.4	$ 969.1
Impact of interest rate hedging program, including related amortization	15.4	9.4
Interest cost capitalized in connection with construction projects (1)	(149.1)	(77.9)
Other (2)	32.1	20.4
Total	$ 961.8	$ 921.0

(1) 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) ratably 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 spending levels and the interest rates charged on borrowings.

(2) Primarily reflects facility commitment fees charged in connection with our revolving credit facilities and amortization of debt issuance costs.

Interest charged on debt principal outstanding, which is the primary driver of interest expense, increased a net $94.3 million year-to-year primarily due to increased debt principal amounts outstanding during 2015, which accounted for a $157.6 million increase, partially offset by the effect of lower overall interest rates in 2015, which accounted for a $63.3 million decrease. Our weighted-average debt principal balance for 2015 was $22.24 billion compared to $18.96 billion during 2014. In general, our debt principal balances have increased over time due to the partial debt financing of our capital spending program. For a discussion of our consolidated debt obligations and capital spending program, see “Liquidity and Capital Resources” within this Part II, Item 7.

Change in fair value of Liquidity Option Agreement

Results for 2015 include $25.4 million of expense we recorded to recognize changes in the fair value 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.

Income taxes

We recognized an overall income tax benefit of $2.5 million for 2015 compared to a provision for income taxes of $23.1 million for 2014. This year-to-year change is primarily due to our accruals for state tax obligations under the Revised Texas Franchise Tax (“Texas Margin Tax”). In June 2015, the State of Texas enacted certain changes to the Texas Margin Tax, which lowered the tax rate.

Noncontrolling interests
Net income attributable to noncontrolling interests decreased $8.9 million in 2015 when compared to 2014 primarily due to the inclusion of noncontrolling interests in Oiltanking from October 1, 2014 to February 13, 2015, which is the date we completed the Oiltanking acquisition.

Comparison of 2014 with 2013

Revenues
Total revenues for 2014 increased $224.2 million when compared to total revenues for 2013. Revenues from the marketing of natural gas increased $609.9 million year-to-year primarily due to higher sales prices, which accounted for a $534.7 million increase. Revenues from the marketing of refined products increased a net $435.7 million year-to-year primarily due to higher sales prices, which accounted for a $502.5 million increase, partially offset by lower sales volumes, which accounted for a $66.8 million decrease. Revenues from the marketing of crude oil decreased a net $584.5 million year-to-year primarily due to lower sales prices, which accounted for a $4.59 billion decrease, partially offset by higher sales volumes, which accounted for a $4.01 billion increase. Revenues from the marketing of NGLs decreased $455.9 million year-to-year primarily due to lower sales prices, which accounted for a $254.8 million decrease, and lower sales volumes, which accounted for an additional $201.1 million decrease. Collectively, revenues from the marketing of octane additives and HPIB decreased $434.0 million year-to-year primarily due to lower sales volumes, which in turn were attributable to lower production volumes caused by unscheduled plant maintenance outages.

Revenues from midstream services increased $648.0 million year-to-year primarily due to the ongoing expansion of our operations. Recently completed assets such as the ATEX pipeline and the Rocky Mountain expansion of our Mid-America Pipeline System as well as certain assets in the Eagle Ford Shale and at our Mont Belvieu complex contributed approximately $400 million of this increase. Also, our consolidated revenues for the fourth quarter of 2014 included $57.5 million from Oiltanking's operations. On October 1, 2014, we acquired a controlling financial interest in Oiltanking; therefore, we began consolidating the financial results of Oiltanking on this date. For additional information regarding the Oiltanking acquisition, see "Significant Recent Developments" within this Part II, Item 7.

Operating costs and expenses
Total operating costs and expenses for 2014 decreased $18.2 million when compared to total operating costs and expenses for 2013. The cost of sales associated with our marketing of natural gas increased $343.5 million year-to-year primarily due to higher purchase prices, which accounted for a $283.8 million increase. Cost of sales associated with our marketing of refined products increased a net $400.4 million year-to-year primarily due to higher purchase prices, which accounted for a $469.5 million increase, partially offset by lower sales volumes, which accounted for a $69.1 million decrease. Cost of sales associated with our marketing of crude oil decreased a net $405.7 million year-to-year primarily due to lower purchase costs, which accounted for a $4.25 billion decrease, partially offset by higher sales volumes, which accounted for a $3.84 billion increase. The cost of sales associated with our marketing of NGLs decreased $383.7 million year-to-year primarily due to lower sales volumes, which accounted for a $255.3 million decrease, and lower purchase costs, which accounted for an additional $128.4 million decrease. Collectively, the cost of sales associated with our marketing of octane additives and HPIB decreased $261.7 million year-to-year primarily due to lower purchase costs, which accounted for a $160.9 million decrease, and lower sales volumes, which accounted for an additional $100.8 million decrease.

Other operating costs and expenses increased $231.4 million year-to-year. The primary driver of this increase is the ongoing expansion of our operations, including that associated with recently completed assets being placed into service (e.g., our ATEX pipeline and expansion of the Rocky Mountain segment of our Mid-America Pipeline System). We estimate that asset expansions accounted for approximately $125.0 million of the $231.4 million increase in expense. In addition, the year-to-year increase includes $18.0 million of expense we recorded in 2014 in connection with a producer settlement involving our San Juan Gathering System and a $16.6 million benefit we recognized in 2013, which represents a negative variance year-to-year, attributable to reductions in a provision for certain pipeline capacity obligations. Other operating costs and expenses for 2014 also include $14.8 million of expenses attributable to Oiltanking's operations in the fourth quarter of 2014.

Depreciation, amortization and accretion expenses in operating costs and expenses increased $133.8 million in 2014 when compared to 2013 primarily due to recently constructed assets being placed into service. Depreciation and amortization expense for 2014 also included $25.0 million attributable to Oiltanking for the fourth quarter of 2014.

We recorded net gains within operating costs and expenses of $102.1 million attributable to asset sales and insurance recoveries in 2014 compared to $83.4 million in 2013. In 2014, we recognized $95.0 million of gains attributable to the receipt of nonrefundable cash insurance proceeds related to our West Storage property damage claims compared to $15.0 million of such gains in 2013. In March 2013, we sold the Stratton Ridge-to-Mont Belvieu segment of the Seminole Pipeline, along with a related storage cavern, and recognized a $52.5 million gain on the sale.

General and administrative costs

General and administrative costs for 2014 increased $26.2 million when compared to 2013 primarily due to higher employee compensation costs, which accounted for $17.3 million of the increase, transaction costs of $3.8 million associated with Step 1 of the Oiltanking acquisition, and $4.7 million of expense for the settlement of litigation.

Equity in income of unconsolidated affiliates

Equity income from our unconsolidated affiliates increased $92.2 million in 2014 when compared to 2013 primarily due to increased earnings from our investments in crude oil pipeline joint ventures.

Interest expense

Interest expense for 2014 increased $118.5 million when compared to 2013. The following table presents the components of our consolidated interest expense for the years indicated (dollars in millions):

	For the Year Ended December 31,	
	2014	**2013**
Interest charged on debt principal outstanding	$ 969.1	$ 911.7
Impact of interest rate hedging program, including related amortization	9.4	3.3
Interest cost capitalized in connection with construction projects	(77.9)	(133.0)
Other	20.4	20.5
Total	$ 921.0	$ 802.5

Interest charged on debt principal outstanding increased a net $57.4 million year-to-year primarily due to increased debt principal amounts outstanding during 2014, which accounted for a $97.9 million increase, partially offset by the effect of lower overall interest rates in 2014, which accounted for a $40.5 million decrease. Our weighted-average debt principal balance for 2014 was $18.96 billion compared to $17.14 billion for 2013. Our debt principal balances have increased over time primarily due to the partial debt financing of our capital spending program. Capitalized interest decreased $55.1 million year-to-year primarily due to assets being placed into service. For a discussion of our consolidated debt obligations and capital spending program, see “Liquidity and Capital Resources” within this Part II, Item 7.

Income taxes

Provision for income taxes decreased $34.4 million in 2014 when compared to 2013 primarily due to changes in our accruals for state tax obligations under the Texas Margin Tax. For additional information regarding our income taxes, see Note 16 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Noncontrolling interests

Net income attributable to noncontrolling interests increased $35.9 million in 2014 when compared to 2013 primarily due to increased earnings from the underlying joint ventures and the inclusion of noncontrolling interests in Oiltanking effective October 1, 2014.

Business Segment Highlights

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our executive management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. We include equity in income of unconsolidated affiliates in our measurement of segment gross operating margin and operating income.

The following table presents gross operating margin by segment for the years indicated (dollars in millions):

	For the Year Ended December 31,		
	2015	**2014**	**2013**
NGL Pipelines & Services	$ 2,771.6	$ 2,877.7	$ 2,514.4
Crude Oil Pipelines & Services	961.9	762.5	742.7
Natural Gas Pipelines & Services	782.6	803.3	789.0
Petrochemical & Refined Products Services	718.5	681.0	625.9
Offshore Pipelines & Services	97.5	162.0	146.1
Total	$ 5,332.1	$ 5,286.5	$ 4,818.1

The GAAP financial measure most directly comparable to total segment gross operating margin is operating income. See “Other Items – Non-GAAP Reconciliations” within this Part II, Item 7 for reconciliations of gross operating margin to operating income for each period presented.

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

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,		
	2015	**2014**	**2013**
Segment gross operating margin:			
Natural gas processing and related NGL marketing activities	$ 895.0	$ 1,162.0	$ 1,165.4
NGL pipelines, storage and terminals	1,380.9	1,145.7	900.0
NGL fractionation	495.7	570.0	449.0
Total	$ 2,771.6	$ 2,877.7	$ 2,514.4
Selected volumetric data:			
NGL pipeline transportation volumes (MBPD)	2,700	2,634	2,541
NGL marine terminal volumes (MBPD)	302	258	246
NGL fractionation volumes (MBPD)	826	824	726
Equity NGL production (MBPD) (1)	133	116	126
Fee-based natural gas processing (MMcf/d) (2)	4,905	4,786	4,612

(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 gas plants.

Natural gas processing and related NGL marketing activities

Comparison of 2015 with 2014
Gross operating margin from natural gas processing and related NGL marketing activities for 2015 decreased $267.0 million when compared to 2014. Gross operating margin from our natural gas processing plants decreased $243.0 million year-to-year primarily due to lower processing margins. In addition, gross operating margin from our NGL marketing activities for 2015 decreased a net $24.0 million when compared to 2014 primarily due to lower sales margins, which accounted for a $167.4 million decrease, partially offset by a $152.0 million increase due to higher sales volumes. During 2015, a higher percentage of volume in the LPG export business was associated with long-term, fee-based marketing contracts rather than spot business, which is typically contracted at higher margins and was prevalent in 2014.

Comparison of 2014 with 2013
Gross operating margin from natural gas processing and related NGL marketing activities for 2014 decreased $3.4 million when compared to 2013. Gross operating margin from our NGL marketing activities for 2014 decreased a net $28.4 million when compared to 2013 primarily due to lower sales margins, which accounted for a $52.9 million decrease, partially offset by a $23.4 million increase due to higher sales volumes, especially for fully-refrigerated, low-ethane propane volumes at our Houston Ship Channel LPG export dock. LPG exports continue to benefit from increased NGL supplies produced from domestic shale plays such as the Eagle Ford Shale and international demand for propane as a feedstock in ethylene plant operations and for power generation and heating purposes.

Gross operating margin from our Pioneer natural gas processing plant increased a net $35.0 million year-to-year primarily due to higher equity NGL production volumes of 6 MBPD, which accounted for a $42.4 million increase, partially offset by lower processing margins, which accounted for a $12.6 million decrease. Gross operating margin from our South Texas natural gas processing plants increased a net $49.9 million year-to-year primarily due to (i) higher processing fees, which accounted for a $24.8 million increase, (ii) higher fee-based processing volumes of 162 MMcf/d, which accounted for a $13.4 million increase and (iii) higher processing margins, which accounted for a $25.2 million increase. Equity NGL production volumes at our South Texas natural gas processing plants decreased 9 MBPD year-to-year, which resulted in a $14.5 million decrease in gross operating margin.

Gross operating margin from our Meeker natural gas processing plant decreased a net $38.0 million year-to-year primarily due to (i) lower processing margins, which accounted for a $19.8 million decrease, (ii) lower equity NGL production volumes of 15 MBPD, which accounted for a $21.9 million decrease, (iii) lower fee based processing volumes of 160 MMcf/d, which accounted for a $9.9 million decrease, partially offset by (iv) higher processing fees, which accounted for a $12.3 million increase. Gross operating margin from our natural gas processing plants in southern Louisiana decreased a net $14.3 million year-to-year primarily due (i) to lower processing margins, which accounted for a $23.6 million decrease, and (ii) lower processing fees, which accounted for a $6.9 million decrease, partially offset by (iii) higher equity NGL production of 7 MBPD, which accounted for an $18.4 million increase. Gross operating margin from our Chaco gas plant decreased $12.1 million year-to-year primarily due to lower processing margins, which accounted for a $5.7 million decrease, and higher operating expenses of $8.4 million associated with plant maintenance projects.

NGL pipelines, storage and terminals

Comparison of 2015 with 2014
Gross operating margin from NGL pipelines, storage and terminal assets for 2015 increased $235.2 million when compared to 2014. Gross operating margin from the Chaparral Pipeline, Mid-America Pipeline System, Seminole Pipeline and related terminals increased $63.2 million in 2015 when compared to 2014. Higher transportation tariffs and other fees, which accounted for a $66.2 million year-to-year increase in gross operating margin, and a $41.1 million year-to-year decrease in operating expenses were partially offset by a $44.1 million decrease in gross operating margin attributable to lower transportation volumes. Transportation volumes on these three pipelines for 2015 decreased a combined 76 MBPD due in part to lower recoveries of ethane when compared to 2014. Lower recoveries of ethane at upstream natural gas processing plants served by these pipelines resulted in lower volumes of ethane available for transportation.

Gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System for 2015 increased $17.8 million primarily due to a combined 28 MBPD increase in transportation volumes (net to our interest) when compared to 2014. Gross operating margin from our ATEX and Aegis pipelines increased $18.6 million year-to-year primarily due to a combined 37 MBPD increase in transportation volumes. Gross operating margin from our South Texas NGL Pipeline System increased $26.5 million year-to-year primarily due to higher transportation volumes of 39 MBPD. Lastly, gross operating margin from our NGL pipelines and related storage assets increased $14.1 million year-to-year as a result of net operational measurement losses during 2014 that did not reoccur in 2015.

Gross operating margin from our Houston Ship Channel marine terminal and related pipeline increased $78.6 million year-to-year primarily due to (i) increased fee revenues of $41.9 million earned in 2015 when compared to 2014 due to the timing of our acquisition of Oiltanking and (ii) $36.7 million due to higher year-to-year marine terminal and pipeline transportation volumes of 47 MBPD and 60 MBPD, respectively. The Houston Ship Channel LPG export terminal continues to earn margin sharing and other fees from our NGL marketing group as it did prior to the Oiltanking acquisition in October 2014. Prior to our acquisition of the terminal, these fees were paid to Oiltanking. Following the acquisition, these fees are charged to our NGL marketing group using intercompany agreements and are reflected in gross operating margin; however, the intercompany amounts are eliminated in the preparation of our consolidated financial statements. With respect to the $41.9 million year-to-year increase, gross operating margin from this terminal for 2015 reflects a full year of these intercompany fees compared to one quarter in 2014.

Comparison of 2014 with 2013

Gross operating margin from NGL pipelines, storage and terminal assets for 2014 increased $245.7 million when compared to 2013. ATEX, which commenced operations in January 2014, contributed $135.6 million of gross operating margin in 2014 and 53 MBPD of transportation volumes. ATEX transports ethane primarily southbound from 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. Gross operating margin for ATEX for 2014 includes $55.2 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated revenues. For additional information regarding the inclusion of deferred revenues in gross operating margin, see "Other Items – Non-GAAP Reconciliations – Gross Operating Margin" within this Part II, Item 7.

Gross operating margin from our Mid-America Pipeline System, Seminole Pipeline and related NGL terminals increased a net $50.5 million year-to-year. The increase in gross operating margin is primarily due to a $103.9 million increase in transportation revenues attributable to the Rocky Mountain pipeline expansion and higher system-wide tariffs, partially offset by a $27.2 million increase in operating costs (e.g., higher fuel and maintenance costs) and a $26.2 million decrease in revenues attributable to a 47 MBPD decline in transportation volumes. Gross operating margin from our South Texas NGL Pipeline System increased $18.0 million year-to-year primarily due to a 35 MBPD increase in transportation volumes primarily associated with Eagle Ford Shale production.

Gross operating margin from our investments in the Front Range Pipeline, Texas Express Pipeline and Texas Express Gathering System increased $23.9 million year-to-year. The year-to-year increase in gross operating margin from these investments includes $7.4 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated equity in income of unconsolidated affiliates. Net to our interest, aggregate transportation volumes on these three pipeline systems were 60 MBPD in 2014.

Gross operating margin from our Houston Ship Channel LPG export marine terminal for the fourth quarter of 2014 includes $19.3 million of intercompany fees earned from providing loading and other services to our NGL marketing group.

NGL fractionation

Comparison of 2015 with 2014
Gross operating margin from NGL fractionation for 2015 decreased $74.3 million when compared to 2014. Gross operating margin from our Mont Belvieu NGL fractionators decreased $62.8 million year-to-year primarily due to lower product blending and other fee revenues as a result of lower commodity prices in 2015. Gross operating margin from our Norco NGL fractionator in Louisiana decreased a net $6.0 million year-to-year primarily due to lower revenues from product blending and percent-of-liquids contracts attributable to lower energy commodity prices, which accounted for a $13.4 million year-to-year decrease, partially offset by an $8.9 million increase due to higher fractionation volumes of 13 MBPD. Gross operating margin from our Hobbs NGL fractionator in Gaines County, Texas decreased $5.1 million year-to-year primarily due to lower fractionation volumes of 8 MBPD.

Comparison of 2014 with 2013
Gross operating margin from NGL fractionation for 2014 increased $121.0 million when compared to 2013 primarily due to higher fractionation volumes and fees at our Mont Belvieu complex. NGL fractionation volumes at our Mont Belvieu complex increased 108 MBPD year-to-year (net to our ownership interest), which resulted in a $113.2 million year-to-year increase in gross operating margin after taking into account associated operating costs. Higher average fractionation and other fees at our Mont Belvieu NGL fractionators accounted for an additional $22.8 million year-to-year increase in gross operating margin. The year-to-year increase in volumes at our Mont Belvieu NGL fractionators is primarily due to an increase in the production of mixed NGLs from domestic shale plays such as the Eagle Ford and other producing regions such as the Rocky Mountains.

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,		
	2015	**2014**	**2013**
Segment gross operating margin	$ 961.9	$ 762.5	$ 742.7
Selected volumetric data:			
Crude oil pipeline transportation volumes (MBPD)	1,474	1,278	1,175
Crude oil marine terminal volumes (MBPD)	557	691	210

Comparison of 2015 with 2014
Gross operating margin from our Crude Oil Pipelines & Services segment for 2015 increased $199.4 million when compared to 2014. Gross operating margin from providing crude oil terminaling services at our Houston Ship Channel facility increased $99.7 million year-to-year primarily due to the timing of the Oiltanking acquisition (gross operating margin from this crude oil terminal for 2015 reflects a full year of operations versus one quarter for 2014). The EFS Midstream system contributed $91.1 million of gross operating margin to our 2015 results along with 65 MBPD of throughput volumes. In addition, gross operating margin from our ECHO terminal in Houston, Texas increased $11.8 million year-to-year due to our completion of an expansion project at this facility during 2015.

Gross operating margin from our equity investment in the Seaway Pipeline increased $76.1 million year-to-year primarily due to contributions from the Seaway Loop. Seaway's transportation volumes increased a net 97 MBPD year-to-year (net to our interest) primarily due to an increase in long-haul volumes. Gross operating margin from our equity investment in the Eagle Ford Crude Oil Pipeline System increased $18.5 million year-to-year primarily due to a 50 MBPD increase in pipeline transportation volumes (net to our interest). Gross operating margin from our West Texas System increased $11.6 million year-to-year primarily due to a 22 MBPD increase in pipeline transportation volumes during 2015.

Gross operating margin from our South Texas Crude Oil Pipeline System decreased $56.5 million year-to-year primarily due to a $45.7 million decrease from the sale of excess crude oil volumes obtained through pipeline tariff allowances and a 15 MBPD decrease in volumes, which accounted for an additional $14.0 million decrease. The decrease in gross operating margin from the sale of excess crude oil volumes by the pipeline was primarily due to lower crude oil prices year-to-year.

Gross operating margin from our crude oil marketing and related trucking activities decreased $53.0 million year-to-year primarily due to lower crude oil sales margins.

Comparison of 2014 with 2013
Gross operating margin from our Crude Oil Pipelines & Services segment for 2014 increased $19.8 million when compared to 2013. Gross operating margin from our crude oil marketing and related activities decreased $161.1 million year-to-year primarily due to lower sales margins attributable to decreases in regional price spreads for crude oil. For example, the average indicative price spread between LLS and WTI crude oil was $9.37 per barrel in 2013 compared to $3.74 per barrel in 2014.

Gross operating margin from our South Texas Crude Oil Pipeline System and West Texas System increased a combined $77.6 million year-to-year primarily due to a combined 58 MBPD increase in transportation volumes. Equity earnings from our investment in the Eagle Ford Crude Oil Pipeline System, which commenced operations in the second quarter of 2013, increased $28.2 million year-to-year on a 52 MBPD increase in transportation volumes (net to our interest).

Gross operating margin from our investment in the Seaway Pipeline increased $30.4 million year-to-year primarily due to higher average tariffs and other fees in 2014, including $9.0 million of capacity fees associated with the commencement of operations on the Seaway Loop in December 2014. The year-to-year increase in gross operating margin from this investment includes $16.7 million of transportation revenues associated with shipper make-up rights that are deferred under GAAP and not reflected in our consolidated equity in income of unconsolidated affiliates. Seaway's transportation volumes decreased a net 18 MBPD year-to-year (net to our interest), with a 42 MBPD decrease in short-haul volumes on the Texas City System partially offset by a 25 MBPD increase on the Freeport System.

Gross operating margin from our ECHO storage terminal increased $17.9 million year-to-year primarily due to an increase in net measurement gains of $8.9 million in 2014 when compared to 2013 and higher storage volumes, which accounted for an $8.6 million increase. Gross operating margin from crude oil terminaling services at our Houston Ship Channel facility was $35.3 million for the fourth quarter of 2014.

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,		
	2015	**2014**	**2013**
Segment gross operating margin	$ 782.6	$ 803.3	$ 789.0
Selected volumetric data:			
Natural gas pipeline transportation volumes (BBtus/d)	12,321	12,476	12,936

Comparison of 2015 with 2014
Gross operating margin from our Natural Gas Pipelines & Services segment for 2015 decreased $20.7 million when compared to 2014.

Gross operating margin from our San Juan Gathering System decreased a net $19.2 million year-to-year primarily due to (i) a $19.7 million decrease in gathering fees, which are indexed to natural gas prices, (ii) a $12.2 million decrease in condensate sales primarily due to lower sales prices and (iii) a $3.1 million decrease due to lower gathering volumes. These decreases were partially offset by an $18.0 million charge recorded in 2014 related to the settlement of a contract dispute with a producer. Gross operating margin from our Piceance Basin and Haynesville Gathering Systems decreased $17.4 million year-to-year primarily due to lower gathering volumes, which accounted for a $12.0 million decrease, and lower gathering fees, which accounted for an additional $5.9 million decrease. Producers served by these three gathering systems have curtailed their drilling programs in response to the continued low price of natural gas. Collectively, natural gas transportation volumes for these three gathering systems decreased 266 BBtus/d year-to-year. Gross operating margin from our Texas Intrastate System decreased $13.6 million year-to-year primarily due to an increase in maintenance and other operating expenses.

Gross operating margin from our Jonah Gathering System increased a net $20.4 million year-to-year primarily due to higher gathering fees, which accounted for an $11.6 million increase and higher transportation volumes of 84 BBtus/d, which accounted for an additional $8.4 million increase. Gross operating margin from our Carlsbad Gathering System in West Texas and New Mexico increased $6.4 million year-to-year primarily due to higher gathering and other fees, which accounted for a $4.1 million increase, and higher volumes of 47 BBtus/d, which accounted for a $3.5 million increase, partially offset by a $2.1 million increase in maintenance and other expenses. Lastly, gross operating margin from our Acadian Gas System increased $5.6 million year-to-year primarily due to lower operating expenses.

Comparison of 2014 with 2013

Gross operating margin from our Natural Gas Pipelines & Services segment for 2014 increased $14.3 million when compared to 2013. Gross operating margin from our natural gas marketing activities increased $28.1 million year-to-year primarily due to higher sales margins, which includes a $13.6 million increase attributable to unrealized, non-cash mark-to-market losses in 2013 that did not reoccur in 2014.

Gross operating margin from our Texas Intrastate System increased $21.6 million year-to-year primarily due to higher pipeline and storage revenues in 2014, which accounted for a $19.2 million increase. Transportation revenues on the Texas Intrastate System increased $17.8 million year-to-year primarily due to higher average fees, which includes a $5.8 million year-to-year increase in firm capacity reservation fees primarily due to producer activity in the Eagle Ford Shale. Overall, natural gas transportation volumes for the Texas Intrastate System increased 40 BBtus/d year-to-year.

Gross operating margin from our San Juan Gathering System decreased a net $8.2 million year-to-year primarily due to $18.0 million of expense in 2014 for the settlement of a contract dispute with a producer and a $4.4 million decrease attributable to lower gathering volumes, both of which were partially offset by a $12.2 million increase attributable to higher gathering fees, which are indexed to natural gas prices. Gross operating margin from our Jonah, Piceance Basin and Haynesville Gathering Systems decreased a combined $24.6 million year-to-year primarily due to lower gathering volumes. Collectively, natural gas transportation volumes for these four gathering systems decreased 412 BBtus/d year-to-year.

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,		
	2015	**2014**	**2013**
Segment gross operating margin:			
Propylene fractionation and related activities	$ 189.5	$ 227.4	$ 134.7
Butane isomerization and related operations	65.2	75.3	99.2
Octane enhancement and related plant operations	144.3	122.4	154.7
Refined products pipelines and related activities	258.8	186.7	164.6
Marine transportation and other	60.7	69.2	72.7
Total	$ 718.5	$ 681.0	$ 625.9
Selected volumetric data:			
Propylene fractionation volumes (MBPD)	71	75	74
Butane isomerization volumes (MBPD)	96	93	94
Standalone DIB processing volumes (MBPD)	79	82	67
Octane additive and related plant production volumes (MBPD)	17	17	20
Pipeline transportation volumes, primarily refined products & petrochemicals (MBPD)	784	758	702
Refined products and petrochemical marine terminal volumes (MBPD)	355	270	5

Propylene fractionation and related activities

Comparison of 2015 with 2014
Gross operating margin from propylene fractionation and related activities decreased $37.9 million for 2015 when compared to 2014. Gross operating margin from our Mont Belvieu propylene fractionation plants decreased $46.4 million year-to-year. This decrease was primarily due to (i) a $28.3 million increase in operating expenses primarily for maintenance activities we completed during 2015, (ii) lower propylene sales volumes, which accounted for a $5.0 million decrease, (iii) lower propylene sales margins, which accounted for an additional $3.9 million decrease, and (iv) a $9.2 million decrease primarily due to lower propylene fractionation and other fees. Gross operating margin from our propylene rail terminal at Mont Belvieu increased $4.4 million for 2015 primarily due to higher fees. Gross operating margin from the remainder of our propylene fractionation business increased $4.1 million for 2015 when compared to 2014 primarily due to operational measurement losses in 2014 that did not reoccur in 2015.

Comparison of 2014 with 2013
Gross operating margin from our propylene fractionation and related activities increased $92.7 million for 2014 when compared to 2013. This increase was primarily due to (i) higher propylene sales margins, which accounted for a $55.0 million increase, (ii) higher propylene sales volumes, which accounted for an $8.8 million increase, (iii) an $11.4 million increase in propylene fractionation fee revenues and (iv) lower operating expenses of $13.1 million at our Mont Belvieu propylene fractionators primarily due to rescheduling of certain maintenance activities to the second quarter of 2015.

Butane isomerization and deisobutanizer operations

Comparison of 2015 with 2014
Gross operating margin from our butane isomerization and deisobutanizer ("DIB") operations decreased $10.1 million for 2015 when compared to 2014. By-product sales revenues decreased $30.7 million year-to-year primarily due to lower sales prices and isomerization revenues decreased $8.1 million year-to-year primarily due to lower fees. The decrease in revenues was partially offset by lower maintenance and other operating expenses, which declined $29.4 million year-to-year.

Comparison of 2014 with 2013
Gross operating margin from our butane isomerization and DIB operations decreased an aggregate $23.9 million for 2014 when compared to 2013. The year-to-year decrease is primarily due to higher maintenance costs incurred during 2014, which accounted for a $14.4 million decrease, and lower by-product sales revenues primarily due to lower commodity prices, which accounted for an $11.5 million decrease.

Octane enhancement and HPIB plant operations

Comparison of 2015 with 2014
Gross operating margin from our octane enhancement facility and HPIB plant increased $21.9 million for 2015 when compared to 2014. The year-to-year increase in gross operating margin is primarily due to higher sales volumes during 2015 when compared to 2014.

Comparison of 2014 with 2013
Gross operating margin from our octane enhancement facility and HPIB plant decreased a net $32.3 million for 2014 when compared to 2013. The year-to-year decrease in gross operating margin is primarily due to an extended period of unscheduled maintenance at the octane enhancement facility during the first quarter of 2014 and reduced operating rates for the remainder of 2014. Production volumes at our octane enhancement facility averaged 15 MBPD in 2014 compared to 18 MBPD in 2013.

Refined products pipelines and related activities

Comparison of 2015 with 2014

Gross operating margin from our refined products pipelines and related marketing activities for 2015 increased $72.1 million when compared to 2014. Gross operating margin from providing refined products and petrochemical terminaling services at Beaumont and on the Houston Ship Channel increased $60.7 million year-to-year primarily due to the timing of the Oiltanking acquisition, which accounted for $45.1 million of the increase (gross operating margin from the acquired assets for 2015 reflects a full year of operations versus one quarter for 2014). Gross operating margin from our TE Products Pipeline and related refined products terminals increased $7.9 million year-to-year primarily due to higher tariffs and other fees. Overall, transportation volumes on the TE Products Pipeline increased a net 30 MBPD year-to-year primarily due to higher refined products and petrochemical transportation volumes.

Comparison of 2014 with 2013

Gross operating margin from our refined products pipelines and related marketing activities for 2014 increased $22.1 million when compared to 2013. Gross operating margin from our TE Products Pipeline and related refined products terminals increased $6.8 million year-to-year primarily due to lower pipeline integrity and other maintenance expenses of $13.1 million and higher transportation tariffs and other fees of $12.2 million, partially offset by a $16.6 million benefit recorded in 2013 related to reductions in a provision for future pipeline capacity obligations on a third party pipeline. Overall, transportation volumes for the TE Products Pipeline increased a net 48 MBPD year-to-year primarily due to higher intrastate shipments of petrochemicals and refined products in southeast Texas, which accounted for a combined 64 MBPD increase, partially offset by lower interstate transportation volumes for refined products and NGLs of 16 MBPD. Interstate components of the TE Products Pipeline were removed from service during 2013 and repurposed to accommodate the southbound delivery of ethane on our ATEX pipeline, which commenced operations in January 2014. Equity earnings from our investment in Centennial Pipeline LLC increased $9.3 million year-to-year primarily due to its recognition in 2014 of previously deferred revenues. Gross operating margin from providing refined products and petrochemical terminaling services in 2014 was $16.3 million, which included $7.4 million attributable to facilities acquired from Oiltanking. Lastly, gross operating margin from our refined products marketing activities decreased $10.3 million year-to-year primarily due to lower sales margins.

Offshore Pipelines & Services

On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. The following table presents segment gross operating margin and selected volumetric data for the Offshore Pipelines & Services segment for the years indicated (dollars in millions, volumes as noted).

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Segment gross operating margin	$ 97.5	$ 162.0	$ 146.1
Selected volumetric data:			
Natural gas transportation volumes (BBtus/d)	587	627	678
Crude oil transportation volumes (MBPD)	357	330	307
Platform natural gas processing (MMcf/d)	101	145	202
Platform crude oil processing (MBPD)	13	14	16

Amounts presented for the 2015 period are through the closing date of the sale, July 24, 2015.

Liquidity and Capital Resources

At December 31, 2015, we had $4.4 billion of consolidated liquidity, which was comprised of $4.38 billion of available borrowing capacity under EPO's revolving credit facilities and $19.0 million of unrestricted cash on hand. Based on current market conditions (as of the filing date of this annual report), we believe we will have sufficient liquidity, cash flow from operations and access to capital markets to fund our capital expenditures and working capital needs for the reasonably foreseeable future.

We expect to issue additional equity and debt securities to assist us in meeting our future funding and liquidity requirements, including those related to capital spending. We have a universal shelf registration statement (the "2013 Shelf") on file with the SEC. The 2013 Shelf allows Enterprise Products Partners L.P. and EPO (each, on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. The 2013 Shelf will expire in June 2016, at which time we expect to file a replacement universal shelf registration statement.

We also have a registration statement on file with the SEC covering the issuance of up to $1.92 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to this at-the-market ("ATM") equity issuance 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. After taking into account the aggregate sale price of common units sold under our ATM program through January 31, 2016, we have the capacity to issue additional common units under this program up to an aggregate sales price of $1.64 billion.

Consolidated Debt

The following table presents scheduled maturities of our consolidated debt obligations outstanding at December 31, 2015 for the years indicated (dollars in millions):

		Scheduled Maturities of Debt					
	Total	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Commercial Paper Notes	$ 1,114.1	$ 1,114.1	$ --	$ --	$ --	$ --	$ --
Senior Notes	20,150.0	750.0	800.0	1,100.0	1,500.0	1,500.0	14,500.0
Junior Subordinated Notes	1,474.4	--	--	--	--	--	1,474.4
Total	$ 22,738.5	$ 1,864.1	$ 800.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 15,974.4

In February 2016, we repaid EPO's $750 million Senior Notes AA using available cash, borrowings under our Multi-Year Revolving Credit Facility and proceeds from the issuance of short-term notes under our commercial paper program.

The following information describes significant transactions that affected our consolidated debt obligations during the year ended December 31, 2015:

Issuance of $2.5 Billion of Senior Notes in May 2015

In May 2015, EPO issued $750 million in principal amount of 1.65% senior notes due May 2018 ("Senior Notes OO"), $875 million in principal amount of 3.70% senior notes due February 2026 ("Senior Notes PP") and $875 million in principal amount of 4.90% senior notes due May 2046 ("Senior Notes QQ") using the 2013 Shelf. Senior Notes OO, PP and QQ were issued at 99.881%, 99.635% and 99.635% of their principal amounts, respectively.

Net proceeds from the issuance of these senior notes were used as follows: (i) the repayment of short-term notes outstanding under EPO's commercial paper program, which included amounts we used to repay $250 million in principal amount of Senior Notes I that matured in March 2015, (ii) the repayment of amounts outstanding at the maturity of our $400 million in principal amount of Senior Notes X that matured in June 2015 and (iii) for general company purposes.

Enterprise Products Partners L.P. has unconditionally guaranteed these senior notes on an unsecured and unsubordinated basis. These senior notes rank equal with EPO's existing and future unsecured and unsubordinated indebtedness and are senior to any existing and future subordinated indebtedness of EPO. These senior notes are subject to make-whole redemption rights and were issued under an indenture containing certain covenants, which generally restrict EPO's ability (with certain exceptions) to incur debt secured by liens and engage in sale and leaseback transactions.

364-Day Credit Agreement

In September 2015, EPO amended its 364-Day Credit Agreement to extend its maturity date to September 2016. There are currently no principal amounts outstanding under this revolving credit agreement. Under the terms of the 364-Day Credit Agreement, EPO may borrow up to $1.5 billion (which may be increased by up to $200 million to $1.7 billion at EPO's election, provided certain conditions are met) at a variable interest rate for a term of 364 days, subject to the terms and conditions set forth therein.

To the extent that principal amounts are outstanding, EPO's obligations under the 364-Day Credit Agreement are not secured by any collateral; however, they are guaranteed by Enterprise Products Partners L.P. If any amounts borrowed under the 364-Day Credit Agreement are outstanding at maturity, 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 2017.

The 364-Day 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 the 364-Day Credit Agreement. The 364-Day Credit Agreement also restricts EPO's ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if a default or an event of default (as defined in the 364-Day Credit Agreement) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

Multi-Year Revolving Credit Facility

In September 2015, EPO amended its Multi-Year Revolving Credit Facility to increase its borrowing capacity from $3.5 billion to $4.0 billion and extend its maturity date from June 2018 to September 2020. The amended agreement also provides that EPO may increase its borrowing capacity to $4.5 billion by allowing existing lenders under the facility to increase their respective commitments or by adding one or more new lenders to the facility. Borrowings under this revolving credit facility may be used for working capital, capital expenditures, acquisitions and general company purposes.

As defined by the credit agreement, variable interest rates charged under this revolving credit facility bear interest at LIBOR plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender's commitment irrespective of commitment usage. This revolving credit facility allows us to request up to two one-year extensions of the maturity date, subject to lender approval.

The Multi-Year Revolving Credit Facility contains certain financial and other customary affirmative and negative covenants. The credit agreement also restricts EPO's ability to pay cash distributions to Enterprise Products Partners L.P. if a default or 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. EPO's borrowings under this revolving credit facility are unsecured general obligations that are guaranteed by Enterprise Products Partners L.P. and are non-recourse to Enterprise GP.

Partial Retirement of Junior Subordinated Notes During 2015

During 2015, EPO repurchased and retired $28.9 million in principal amount of its Junior Subordinated Notes A and $29.4 million in principal amount of its Junior Subordinated Notes C with cash from operations. A $1.6 million gain on the extinguishment of these debt obligations is included in "Other, net" on our Statements of Consolidated Operations.

Issuance of Common Units

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

	Number of Common Units Issued	Net Cash Proceeds Received
Year Ended December 31, 2013:		
Common units issued in connection with underwritten offerings	36,800,000	$ 1,039.6
Common units issued in connection with ATM program	15,249,378	456.3
Common units issued in connection with DRIP and EUPP	10,308,254	296.1
Total	62,357,632	$ 1,792.0
Year Ended December 31, 2014:		
Common units issued in connection with ATM program	1,590,334	$ 57.7
Common units issued in connection with DRIP and EUPP	9,754,227	331.1
Total	11,344,561	$ 388.8
Year Ended December 31, 2015:		
Common units issued in connection with ATM program	25,520,424	$ 817.4
Common units issued in connection with DRIP and EUPP	12,793,913	371.2
Total	38,314,337	$ 1,188.6

The following information describes significant transactions that affected our partners' equity accounts during the year ended December 31, 2015:

Completion of Oiltanking Acquisition

In February 2015, we issued 36,827,517 common units to the former public unitholders of Oiltanking as a result of completing Step 2 of the Oiltanking acquisition. See "Significant Recent Developments" within this Part II, Item 7 for additional information regarding the Oiltanking acquisition.

ATM Program

During the year ended December 31, 2015, we issued 25,520,424 common units under the ATM program for aggregate gross cash proceeds of $825.4 million. This includes 3,225,057 common units sold in March 2015 to a privately held affiliate of EPCO, which generated gross proceeds of $100 million. After taking into account applicable costs, our transactions under the ATM program resulted in aggregate net cash proceeds of $817.4 million for the year ended December 31, 2015.

In January 2016, we sold an aggregate 3,830,256 common units under the ATM program to privately held affiliates of EPCO, which generated gross proceeds of $100 million.

DRIP and EUPP

We also have registration statements on file with the SEC collectively authorizing the issuance of up to 140,000,000 of our common units 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 new common units.

We issued a total of 12,413,351 common units under our DRIP during 2015, which generated net cash proceeds of $359.8 million. This includes the reinvestment of $100 million by privately held affiliates of EPCO that resulted in the issuance of 3,443,631 common units (this amount being a component of the total common units issued under the DRIP in 2015). After taking into account the number of common units issued under the DRIP through December 31, 2015, we had the capacity to issue an additional 15,067,998 common units under this plan.

In February 2016, privately held affiliates of EPCO reinvested an additional $100 million, resulting in the issuance of 4,481,504 common units under our DRIP.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 8,000,000 of our common units in connection with our EUPP. We issued 380,562 common units under our EUPP during 2015, which generated net cash proceeds of $11.4 million. After taking into account the number of common units issued under the EUPP through December 31, 2015, we had the capacity to issue an additional 6,772,506 common units under this plan.

Use of Proceeds

The net cash proceeds we received from the issuance of common units during 2015 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facilities and for general company purposes.

For additional information regarding our issuance of common units and related registration statements, see Note 9 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Credit Ratings

As of February 26, 2016, the investment-grade credit ratings of EPO's long-term senior unsecured debt securities were BBB+ from Standard and Poor's and Baa1 from Moody's. In addition, the credit ratings of EPO's short-term senior unsecured debt securities were A-2 from Standard and Poor's and P-2 from Moody's. Fitch Ratings issued non-solicited ratings of BBB+ and F-2 for EPO's long-term senior unsecured debt securities and short-term senior unsecured debt securities, respectively.

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.

Cash Flows from Operating, Investing and Financing Activities

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,		
	2015	**2014**	**2013**
Net cash flows provided by operating activities	$ 4,002.4	$ 4,162.2	$ 3,865.5
Cash used in investing activities	$ 3,441.8	$ 5,797.9	$ 4,257.5
Cash provided by (used in) financing activities	$ (616.0)	$ 1,653.2	$ 432.8

Net cash flows provided by operating activities are largely dependent on earnings from our consolidated business activities. 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 counterparties 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.

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, such as those experienced throughout 2015 and that we continue to experience at the beginning of 2016, increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings or small-scale companies. Such non-performance risk could be associated with long-term contracts with minimum volume commitments or fixed demand charges. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

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

For a more complete discussion of these and other risk factors pertinent to our business, see Part I, Item 1A of this annual report.

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

Comparison of 2015 with 2014

Operating Activities
Net cash flows provided by operating activities for the year ended December 31, 2015 decreased $159.8 million when compared to the year ended December 31, 2014. The decrease in cash provided by operating activities was primarily due to:

- a $215.1 million year-to-year decrease in cash primarily due to the timing of cash receipts and payments related to operations; and

- a $31.7 million decrease in cash attributable to lower partnership income in 2015 compared to 2014 (after adjusting our $275.1 million year-to-year decrease in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows); partially offset by

- an $87.0 million year-to-year increase in cash distributions received from unconsolidated affiliates generally attributable to our investments in crude oil and NGL pipeline joint ventures.

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.

Investing Activities
Cash used in investing activities for the year ended December 31, 2015 decreased $2.36 billion when compared to the year ended December 31, 2014 primarily due to:

- a $1.46 billion year-to-year increase in cash proceeds from asset sales and insurance recoveries primarily due to the sale of our Offshore Business in July 2015, which generated proceeds of $1.53 billion (see “Significant Recent Developments – Sale of Offshore Business” under this Part II, Item 7);

- a $1.1 billion cash payment in July 2015 (the initial installment) for the acquisition of EFS Midstream compared to an aggregate $2.42 billion cash payment made in October 2014 in connection with Step 1 of the Oiltanking acquisition; and

- a $559.8 million year-to-year decrease in cash contributions to our unconsolidated affiliates primarily due to the completion of construction of the Front Range Pipeline and the Seaway Loop in 2014, partially offset by increased investments in the Eagle Ford Terminals Corpus Christi and Delaware Gas Basin Processing Plant in 2015; partially offset by

- a $947.6 million year-to-year increase in capital spending for consolidated property, plant and equipment, net of contributions in aid of construction costs (see "Capital Spending" within this Part II, Item 7 for additional information regarding our capital spending program); and

- an $81.5 million year-to-year change in restricted cash requirements.

Financing Activities
Net cash used in financing activities for the year ended December 31, 2015 was $616.0 million compared to net cash provided by financing activities of $1.65 billion for the year ended December 31, 2014. The $2.27 billion year-to-year change in cash flow from financing activities was primarily due to:

- a $2.81 billion year-to-year decrease in net borrowings under our consolidated debt agreements. EPO issued $2.5 billion in senior notes and repaid $1.48 billion in principal amount of debt obligations in 2015 compared to the issuance of $4.75 billion and repayment of $1.15 million in principal amount of senior notes in 2014. In addition, net proceeds from the issuance of short-term notes under EPO's commercial paper program were $202.2 million in 2015 compared to $430.6 million in 2014; and

- a $305.6 million year-to-year increase in cash distributions paid to limited partners in 2015 when compared to 2014. 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; partially offset by

- a $799.8 million year-to-year increase in net cash proceeds from the issuance of common units.

Comparison of 2014 with 2013

Operating Activities
Net cash flows provided by operating activities for the year ended December 31, 2014 increased $296.7 million when compared to the year ended December 31, 2013. The increase in cash provided by operating activities was primarily due to:

- a $183.8 million increase in cash attributable to higher partnership income in 2014 compared to 2013 (after adjusting our $226.4 million year-to-year increase in net income for changes in the non-cash items identified on our Statements of Consolidated Cash Flows); and

- a $123.5 million year-to-year increase in cash distributions received from unconsolidated affiliates primarily due to increased earnings from our investments in crude oil and NGL pipeline joint ventures (e.g., our Eagle Ford Crude Oil Pipeline System, Texas Express Pipeline, Seaway Pipeline and Front Range Pipeline).

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.

Investing Activities
Cash used in investing activities for the year ended December 31, 2014 increased $1.54 billion when compared to the year ended December 31, 2013 primarily due to:

- a net $2.42 billion cash payment in October 2014 in connection with Step 1 of the Oiltanking acquisition; and

- an aggregate $135.3 million year-to-year decrease in cash proceeds from asset sales and insurance recoveries (see Note 19 of the Notes to Consolidated Financial Statements under Part II, Item 8 of this annual report for additional information regarding proceeds from asset sales and insurance recoveries); partially offset by

- a $518.2 million year-to-year decrease in capital expenditures for consolidated property, plant and equipment, net of contributions in aid of construction costs;

- a $371.7 million year-to-year decrease in cash contributions to our unconsolidated affiliates primarily due to the completion of construction of the Texas Express Pipeline, SEKCO Oil Pipeline, Front Range Pipeline and Seaway Pipeline looping project, partially offset by increased investments in the Eagle Ford Crude Oil Pipeline System; and

- a $126.9 million year-to-year change in restricted cash requirements.

Financing Activities

Net cash provided by financing activities for the year ended December 31, 2014 increased $1.22 billion when compared to the year ended December 31, 2013 primarily due to:

- a $2.85 billion year-to-year increase in net borrowings under our consolidated debt agreements. EPO issued $4.75 billion and repaid $1.15 billion in principal amount of senior notes in 2014, compared to the issuance of $2.25 billion and repayment of $1.2 billion in principal amount of senior notes in 2013. In addition, net borrowings under EPO's revolving credit facilities and net proceeds from the issuance of short-term notes under its commercial paper program increased an aggregate of $303.4 million year-to-year; and

- a $196.4 million year-to-year change related to the monetization of interest rate derivative instruments. A $27.6 million gain was recorded in 2014 compared to a $168.8 million loss in 2013; partially offset by

- a $1.4 billion year-to-year decrease in net cash proceeds from the issuance of common units;

- a $237.8 million year-to-year increase in cash distributions paid to limited partners in 2014 when compared to 2013. 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; and

- a $111.4 million year-to-year decrease in cash contributions from noncontrolling interests primarily due to contributions we received during 2013 related to a joint venture involving NGL fractionators at our complex in Mont Belvieu, Texas.

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, for example, those for capital expenditures, debt service, working capital, operating expenses, commitments and contingencies and other significant 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.

We measure available cash by reference to "distributable cash flow," which is a non-GAAP financial measure. Distributable cash flow is an important non-GAAP 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 or support an increase in our quarterly cash distributions. Distributable cash flow is also a quantitative standard used by the investment community with respect to publicly traded partnerships because 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 distributable cash flow we generate to the cash distributions we expect to pay our partners. Using this metric, management computes our distribution coverage ratio.

Based on the level of available cash, management proposes a quarterly cash distribution rate to the Board of Enterprise GP, which has sole authority in approving such matters. Unlike most 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 IDRs or other equity interests.

Our use of distributable cash flow for the limited purposes described above and in this report is not a substitute for net cash flows provided by operating activities, the most comparable GAAP measure. For a reconciliation of non-GAAP distributable cash flow to net cash flows provided by operating activities, see "Other Items – Non-GAAP Reconciliations" within this Part II, Item 7.

The following table summarizes our calculation of distributable cash flow for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Net income attributable to limited partners (1)	$ 2,521.2	$ 2,787.4	$ 2,596.9
Adjustments to GAAP net income attributable to limited partners to derive non-GAAP distributable cash flow:			
Add depreciation, amortization and accretion expenses	1,516.0	1,360.5	1,217.6
Add non-cash asset impairment charges	162.6	34.0	92.6
Add loss or subtract gains attributable to asset sales and insurance recoveries, net	15.6	(102.1)	(83.3)
Add cash proceeds from asset sales and insurance recoveries (2)	1,608.6	145.3	280.6
Add changes in fair value of Liquidity Option Agreement (3)	25.4	--	--
Add cash distributions received from unconsolidated affiliates (4)	462.1	375.1	251.6
Subtract equity in income of unconsolidated affiliates (4)	(373.6)	(259.5)	(167.3)
Subtract sustaining capital expenditures (5)	(272.6)	(369.0)	(291.7)
Add gains or subtract losses from monetization of interest rate derivative instruments accounted for as cash flow hedges (6)	--	27.6	(168.8)
Add deferred income tax expense or subtract benefit, as applicable	(20.6)	6.1	37.9
Other, net	(37.4)	73.2	(15.7)
Distributable cash flow	$ 5,607.3	$ 4,078.6	$ 3,750.4
Total cash distributions paid to limited partners with respect to period	$ 3,036.8	$ 2,707.6	$ 2,461.9
Cash distributions per unit declared by Enterprise GP with respect to period (7)	$ 1.5300	$ 1.4500	$ 1.3700
Total distributable cash flow retained by partnership with respect to period (8)	$ 2,570.5	$ 1,371.0	$ 1,288.5
Distribution coverage ratio (9)	1.85x	1.51x	1.52x

(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 "Consolidated Income Statements Highlights" within this Part II, Item 7.

(2) For a discussion of significant changes in cash proceeds from asset sales and insurance recoveries as presented in the investing activities section of our Statements of Consolidated Cash Flows, see "Cash Flows from Operating, Investing and Financing Activities" within this Part II, Item 7.

(3) 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.

(4) For information regarding our unconsolidated affiliates, see Note 6 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

(5) For a discussion of our capital spending activity, see "Capital Spending" within this Part II, Item 7. For purposes of this calculation, sustaining capital expenditures for each period include the impact of accruals.

(6) For information regarding these gains and losses, 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.

(7) See Note 9 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 periods presented.

(8) At the sole discretion of Enterprise GP, cash retained by the partnership with respect to each of these years was primarily reinvested in our growth capital spending program, which substantially reduced our reliance on the equity and debt capital markets to fund such major expenditures.

(9) 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.

Our management compares the distributable cash flow we generate to the cash distributions we expect to pay our partners. Using this metric, management computes our distribution coverage ratio. The GAAP measure most directly comparable to distributable cash flow is net cash flows provided by operating activities.

Designated Units Issued in Connection with Holdings Merger

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (the "Holdings Merger"). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). Distributions paid by us to this privately held affiliate of EPCO during 2015 excluded 35,380,000 Designated Units. The temporary distribution waiver expired at the end of calendar year 2015; therefore, distributions to be paid, if any, during calendar year 2016 will include all common units owned by the privately held affiliates of EPCO.

Capital Spending

An important part of our business strategy involves expansion through growth capital projects, business combinations and investments in joint ventures. We believe that we are 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 Rocky Mountains, Mid-Continent, Northeast and U.S. Gulf Coast regions, including the Niobrara, Barnett, Eagle Ford, Permian, Haynesville, Marcellus and Utica 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. In light of current business conditions, we expect that these opportunities will increase.

Based on total project costs, we placed approximately $2.7 billion of major capital projects into service during 2015. These projects included expansions of our Houston Ship Channel LPG export terminal and the completion of Aegis. We expect to complete construction on an additional $2.7 billion of major capital projects during 2016, including our ethane export terminal, two natural gas processing plants in the Permian Basin and various crude oil and refined products infrastructure.

We currently expect our total capital spending for the year ended December 31, 2016 to approximate $3.8 billion to $4.1 billion, which includes the $1.0 billion final installment for EFS Midstream and $275 million for sustaining capital expenditures. Our forecast of capital spending for 2016 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 spending due to factors beyond our control, such as adverse economic conditions, weather related issues and changes in supplier prices. Furthermore, our forecast of capital spending 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 the formation of joint ventures 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 spending for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2015	**2014**	**2013**
EFS Midstream acquisition	$ 1,056.5		
Oiltanking acquisition:			
Cash consideration		$ 2,416.8	
Equity consideration	1,408.7	2,171.5	
Capital spending for property, plant and equipment, net:			
Growth capital projects (1)	3,540.0	2,502.8	$ 3,088.0
Sustaining capital projects (2)	271.6	361.2	294.2
Investments in unconsolidated affiliates	162.6	722.4	1,094.1
Other investing activities	5.3	5.8	1.0
Total capital spending	$ 6,444.7	$ 8,180.5	$ 4,477.3

(1) 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.

(2) 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 spending 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, 2015 involved projects at our Houston LPG and ethane export terminals and Mont Belvieu complex. Fluctuations in spending for sustaining capital projects are explained in large part by the timing and cost of pipeline integrity and similar projects.

Comparison of 2015 with 2014

We acquired EFS Midstream in July 2015 for approximately $2.1 billion in cash, excluding $125 million of EFS Midstream debt that was extinguished immediately after closing of the transaction. Of the $2.1 billion purchase price, $1.0 billion was deferred and will be paid no later than the first anniversary of the closing date. For additional information regarding the EFS Midstream acquisition, including an allocation of the purchase price to assets acquired and liabilities assumed, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Capital spending for 2015 included $1.4 billion of non-cash equity consideration we issued to complete Step 2 of the Oiltanking acquisition. Step 2 represented our acquisition of the noncontrolling interests in Oiltanking; therefore, approximately $1.4 billion of noncontrolling interests attributable to Oiltanking was reclassified to limited partners' equity to reflect the February 2015 issuance of 36,827,517 of our common units. Capital spending for 2014 reflected total cash and equity consideration of approximately $4.6 billion to OTA to complete Step 1 of the Oiltanking acquisition. For information regarding the Oiltanking acquisition, see Note 12 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

In total, capital spending for property, plant and equipment increased $947.6 million year-to-year primarily due to higher growth capital spending during 2015. Growth capital spending at our Mont Belvieu complex increased $385.2 million year-to-year primarily due to construction of the PDH facility, which is expected to begin commercial operations in 2017.

Growth capital spending at our Houston Ship Channel LPG and ethane export facilities increased a combined $282.6 million year-to-year. We recently completed expansion projects at our Houston Ship Channel LPG export terminal that increased our ability to load cargoes of fully refrigerated, low-ethane propane to approximately 16.0 MMBbls per month. Work also continues at our Houston Ship Channel ethane export facility, which we expect to begin operations in the third quarter of 2016.

Growth capital spending on our natural gas processing and related pipeline projects in the Delaware Basin increased a combined $235.2 million year-to-year. Our South Eddy natural gas processing plant and related pipeline infrastructure are expected to begin operations in the second quarter of 2016. In addition, we are constructing and will own an 82-mile NGL pipeline to connect the new Delaware Basin natural gas processing plant to our Chaparral NGL pipeline. We expect this pipeline to begin operations in mid-2016.

Growth capital spending on our Rancho II crude oil pipeline, a component of our South Texas Crude Oil Pipeline System, and the expansion of crude oil terminal assets at our ECHO, Houston Ship Channel and Beaumont Marine West terminals increased a combined $218.2 million year-to-year. The Rancho II crude oil pipeline, which entered commercial service in September 2015, consists of 89 miles of pipeline extending from Sealy, Texas to our ECHO terminal. Current expansion projects at our ECHO, Houston Ship Channel and Beaumont Marine West terminals involve the construction of additional storage capacity and associated distribution pipelines. We continue to complete these terminal expansion projects in phases, with final completion expected in 2016.

Growth capital spending on our Gulf Coast ethane header system increased $208.0 million year-to-year. Our Gulf Coast ethane header system extends 500 miles from Corpus Christi, Texas to the Mississippi River in Louisiana and is comprised of the Aegis pipeline and other South Texas midstream infrastructure.

Growth capital spending attributable to ATEX and the Rocky Mountain expansion of our Mid-America Pipeline System decreased a combined $264.2 million year-to-year. These two projects were completed during the first quarter of 2015.

Investments in unconsolidated affiliates decreased $559.8 million year-to-year primarily due to completion of the Seaway Loop pipeline in December 2014.

Comparison of 2014 with 2013

On October 1, 2014, we acquired the general partner and related IDRs, 15,899,802 common units and 38,899,802 subordinated units of Oiltanking from OTA. We paid total consideration of approximately $4.4 billion to OTA comprised of $2.21 billion in cash and 54,807,352 of our common units for these ownership interests and rights. We also paid $228.3 million to acquire from OTA outstanding loans payable by Oiltanking or its subsidiaries. Collectively, these transactions are referred to as “Step 1” of the Oiltanking acquisition.

In total, capital spending for property, plant and equipment decreased $518.2 million year-to-year primarily due to lower growth capital spending during 2014. Capital spending for growth projects in the Eagle Ford Shale and at our Mont Belvieu complex decreased a combined $408.3 million year-to-year. Since 2010, expansion of midstream infrastructure in the Eagle Ford Shale region has been a strategic focus for us. We constructed new NGL, natural gas and crude oil pipelines and the Yoakum natural gas processing plant to facilitate production growth from Eagle Ford Shale producers. Our build-out in this supply basin was substantially complete in 2013. Likewise, we completed and placed into service the seventh and eight NGL fractionators at our Mont Belvieu complex in September 2013 and November 2013, respectively.

Growth capital spending for ATEX and Aegis decreased a net $554.1 million year-to-year. ATEX was placed into service in the first quarter of 2014. Growth capital spending for our LPG, ethane and refined products export facilities increased $324.1 million year-to-year. In May 2014, we began loading cargoes of refined products for export at our reactivated marine terminal located in Beaumont, Texas.

Investments in unconsolidated affiliates during 2014 decreased $371.7 million when compared to 2013. Our spending on the expansion and construction of joint venture crude oil pipelines decreased a net $106.9 million. Spending related to our construction of the Texas Express Pipeline, Texas Express Gathering System and Front Range Pipeline decreased a combined $262.7 million year-to-year.

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:

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

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

At December 31, 2015 and 2014, the net carrying value of our property, plant and equipment was $32.03 billion and $29.88 billion, respectively. We recorded $1.16 billion, $1.11 billion and $1.01 billion of depreciation expense for the years ended December 31, 2015, 2014 and 2013, respectively. For additional information regarding our property, plant and equipment, see Note 5 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, which include property, plant and equipment and intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Examples of such events or changes might be production declines that are not replaced by new discoveries or long-term decreases in the demand or price of natural gas, NGLs, crude oil, petrochemicals or refined products. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the asset. Estimates of undiscounted cash flows are based on a number of assumptions including anticipated operating margins and volumes; estimated useful life of the asset or asset group; and estimated residual values. If the carrying value of a long-lived asset is not recoverable, an impairment charge would be recorded for the excess of a long-lived asset's carrying value over its estimated fair value, which is derived from an analysis of the asset's estimated future cash flows, the market value of similar assets and replacement cost of the asset less any applicable depreciation or amortization. In addition, fair value estimates also include usage of probabilities for a range of possible outcomes.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible permanent loss in value of the investment (i.e., other than a temporary decline). Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee's industry. When evidence of a loss in value has occurred, we compare the estimated fair value of the investment to the carrying value of the investment 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 life of the investment's underlying assets.

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

During 2015, 2014 and 2013, we recognized non-cash asset impairment charges related to long-lived assets of $162.6 million, $34.0 million and $92.6 million, respectively, which are a component of operating 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.

Amortization Methods and Estimated Useful Lives of Customer Relationships and Contract-Based Intangible Assets

The specific, identifiable intangible assets of a 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 certain relationships acquired in connection with business combinations and asset purchases whereby (i) we acquired information about or access to customers and now have the ability to provide services to them and (ii) the customers now have the ability to make direct contact with us. Customer relationships may arise from contractual arrangements (such as service contracts) and through means other than contracts, such as through regular contact by sales or service representatives. The value we assign to customer relationships is amortized to earnings using methods that closely resemble the pattern in which the economic benefits 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 periods for certain of our customer relationship intangible assets are limited by the estimated finite economic life of the associated hydrocarbon resource basins. In this context, our estimate of the useful life of each resource basin is predicated on a number of factors, including reserve estimates and the economic viability of production and exploration activities.

Contract-based intangible assets represent specific commercial rights we own arising from discrete contractual agreements, such as the long-term rights we possess under the Shell natural gas processing agreement and the Jonah natural gas transportation contracts. A contract-based intangible asset with a finite life is amortized over its estimated economic life, which is the period over which the asset 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 fractionation facility, pipeline or other asset), (ii) any legal or regulatory developments that would impact such contractual rights and (iii) any contractual provisions that enable us to renew or extend such 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 unamortized cost is not recoverable due to impairment, 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, 2015 and 2014, the carrying value of our customer relationship and contract-based intangible asset portfolio was $4.04 billion and $2.84 billion, respectively. The carrying value of this portfolio increased $1.41 billion in connection with the acquisition of EFS Midstream in July 2015. We recorded $174.1 million, $110.6 million and $105.6 million of amortization expense attributable to intangible assets for the years ended December 31, 2015, 2014 and 2013, respectively. For additional information regarding our intangible assets, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Methods We Employ to Measure the Fair Value of Goodwill 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 determining 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 businesses that make up the reporting unit. Such 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 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 charge to operating costs and expenses is required to reduce the carrying value of goodwill to its implied fair value. At December 31, 2015 and 2014, the carrying value of our goodwill was $5.75 billion and $4.3 billion, respectively.

In October 2014, we recorded $2.22 billion of goodwill in connection with Step 1 of our acquisition of Oiltanking. In addition, we recorded an indefinite-life intangible asset valued at $1.46 billion in connection with the acquisition of Oiltanking's IDRs. The IDRs represented contractual rights to the incentive cash distributions to be paid by Oiltanking to its general partner. Immediately after completion of the Oiltanking Merger in February 2015, the IDRs were cancelled in exchange for limited partner interests in Oiltanking, and the carrying value of this intangible asset was reclassified to goodwill. We attribute the goodwill resulting from the acquisition of Oiltanking to our ability to leverage the acquired business with our existing asset base to create future business opportunities. These opportunities include the marketing of NGLs, crude oil, condensate and refined products.

We did not record any goodwill impairment charges in 2015, 2014 or 2013. Based on our most recent goodwill impairment test at December 31, 2015, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%). For additional information regarding our goodwill, see Note 7 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists; (ii) delivery has occurred or services have been rendered; (iii) the buyer's price is fixed or determinable; and (iv) collectibility is reasonably assured. We record revenue when sales contracts are settled (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). We record any necessary allowance for doubtful accounts as required by our established policy. For additional information regarding our revenue recognition policies, see Note 3 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Our use of estimates for certain revenues and expenses has increased as a result of SEC regulations that require us to submit financial information on accelerated time frames. Such estimates are necessary due to the time required to compile actual billing information and receive third party data needed to record transactions for financial reporting purposes. One example of our use of estimates is the accrual of an estimate of processing plant revenue and the cost of natural gas for a given month (prior to receiving actual customer and vendor-related plant operating information for a specific period). These estimates reverse in the following month and are offset by the corresponding actual customer billing and vendor-invoiced amounts. Accordingly, we include one month of certain estimated data in our results of operations. Such estimates are generally based on actual volume and price data through the first part of the month and estimated for the remainder of the month.

Changes in facts and circumstances may result in revised estimates and could affect our reported financial statements and accompanying disclosures. If the assumptions underlying our revenue and expense estimates prove to be substantially incorrect, it could result in material adjustments in results of operations between periods. We review our estimates based on currently available information.

Other Items

Contractual Obligations

The following table summarizes our significant contractual obligations at December 31, 2015 (dollars in millions):

		Payment or Settlement due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Scheduled maturities of debt obligations (1)	$ 22,738.5	$ 1,864.1	$ 1,900.0	$ 3,000.0	$ 15,974.4
Estimated cash payments for interest (2)	$ 21,734.1	$ 1,053.0	$ 2,011.7	$ 1,777.2	$ 16,892.2
Operating lease obligations (3)	$ 494.0	$ 64.2	$ 108.7	$ 85.7	$ 235.4
Purchase obligations: (4)					
Product purchase commitments:					
Estimated payment obligations:					
Natural gas	$ 1,160.8	$ 451.3	$ 431.2	$ 217.3	$ 61.0
NGLs	$ 376.9	$ 319.3	$ 45.7	$ 11.9	$ --
Crude oil	$ 441.5	$ 389.4	$ 35.8	$ 16.3	$ --
Petrochemicals and refined products	$ 1,921.4	$ 1,868.6	$ 52.8	$ --	$ --
Other	$ 33.2	$ 8.7	$ 11.0	$ 6.8	$ 6.7
Underlying major volume commitments:					
Natural gas (in TBtus)	647	243	256	118	30
NGLs (in MMBbls)	39	30	7	2	--
Crude oil (in MMBbls)	14	11	2	1	--
Petrochemicals and refined products (in MMBbls)	146	126	20	--	--
Service payment commitments (5)	$ 685.9	$ 184.5	$ 251.9	$ 114.8	$ 134.7
Capital expenditure commitments (6)	$ 113.9	$ 113.9	$ --	$ --	$ --
Other long-term liabilities (7)	$ 411.5	$ --	$ 17.8	$ 4.8	$ 388.9
Total	$ 50,111.7	$ 6,317.0	$ 4,866.6	$ 5,234.8	$ 33,693.3

(1) Represents scheduled future maturities of our consolidated debt principal obligations. For information regarding our consolidated debt obligations, see Note 8 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, 2015, the contractually scheduled maturities of such balances, and the applicable fixed or variable interest rates paid during 2015. With respect to our variable-rate debt obligations, we applied the weighted-average interest rate paid during 2015 to determine the estimated cash payments. See Note 8 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report for the weighted-average variable interest rate charged in 2015 in connection with our commercial paper program. In general, our estimated cash payments for interest are significantly influenced by the long-term maturities of our junior subordinated notes (due August 2066 through January 2068). Our estimated cash payments for interest with respect to each junior subordinated note are based on the current fixed interest rate for each note applied to the entire remaining term through the respective maturity date.

(3) Primarily represents land held pursuant to right-of-way agreements and 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, 2015. The estimated payment obligations are based on contractual prices in effect at December 31, 2015 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery.

(5) Primarily represents our unconditional payment obligations under firm pipeline transportation contracts.

(6) Represents unconditional payment obligations for services to be rendered or products to be delivered in connection with our capital spending program, including our share of the capital spending of our unconsolidated affiliates.

(7) As reflected on our consolidated balance sheet at December 31, 2015, "Other long-term liabilities" primarily represent the Liquidity Option Agreement, the noncurrent portion of asset retirement obligations and deferred revenues.

In connection with the agreements to acquire EFS Midstream, we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for Pioneer and Reliance, if requested by these 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. Due to the uncertain timing of these 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.

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.

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 Matters
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.

Regulation
For information regarding the impact of federal, state or local regulatory measures on our business, see "Regulatory Matters" included under Part I, Item 1 and 2 of this annual report.

Recent Accounting Developments
For information regarding recent accounting developments, see Note 2 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Non-GAAP Reconciliations

Gross operating margin
The following table presents a reconciliation of non-GAAP total segment gross operating margin to GAAP operating income for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Total segment gross operating margin	$ 5,332.1	$ 5,286.5	$ 4,818.1
Adjustments to reconcile total segment gross operating margin to operating income:			
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(1,428.2)	(1,282.7)	(1,148.9)
Subtract impairment charges not reflected in gross operating margin	(162.6)	(34.0)	(92.6)
Add net gains or subtract net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	(15.6)	102.1	83.4
Subtract non-refundable deferred revenues attributable to shipper make-up rights on new pipeline projects reflected in gross operating margin	(53.6)	(84.6)	(4.4)
Add subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	60.7	2.9	--
Subtract general and administrative costs not reflected in gross operating margin	(192.6)	(214.5)	(188.3)
Operating income	$ 3,540.2	$ 3,775.7	$ 3,467.3

The results of operations from our liquids pipelines are primarily dependent upon the volumes transported and the associated fees we charge for these transportation services. Typically, pipeline transportation revenue is recognized when volumes are transported and delivered. However, under certain pipeline transportation agreements, customers are required to ship a minimum volume over an agreed-upon period. These arrangements typically entail the shipper paying a transportation fee based on a minimum volume commitment, with a provision that allows the shipper to make-up any volume shortfalls over the agreed-upon period (referred to as shipper "make-up rights"). Revenue attributable to shipper make-up rights is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired (typically a one year contractual period), or when the pipeline is otherwise released from its transportation service performance obligation.

However, management includes deferred transportation revenues relating to the "make-up rights" of committed shippers when reviewing the financial results of certain major new pipeline projects such as ATEX. From an internal (and segment) reporting standpoint, management considers the transportation fees paid by committed shippers on major new 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. Since management includes these deferred revenues in non-GAAP gross operating margin, these amounts are deducted in determining GAAP-based operating income. Our consolidated revenues do not reflect any deferred revenues until the conditions for recognizing such revenues are met in accordance with GAAP.

Several of our major new liquids pipeline projects experienced periods where shippers were unable to meet their contractual minimum volume commitments. In general, we expect that these types of shortfalls will continue in 2016 due to the current business environment, with the recognition of revenue associated with past deferrals associated with make-up rights partially or entirely offsetting any new make-up right deferrals.

The following table summarizes the deferred revenue amounts attributable to shipper make-up rights included in gross operating margin for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2015	**2014**	**2013**
NGL Pipelines & Services:			
Texas Express Pipeline (1,2)	$ 2.2	$ 3.2	$ 1.3
Front Range Pipeline (1,2)	1.0	5.5	--
ATEX (3)	28.7	55.2	--
Aegis	0.5	0.9	--
Total segment gross operating margin	32.4	64.8	1.3
Crude Oil Pipelines & Services:			
Seaway Pipeline (1,4)	21.2	19.8	3.1
Total segment gross operating margin	21.2	19.8	3.1
Total amount included in overall gross operating margin	$ 53.6	$ 84.6	$ 4.4

(1) Amounts presented represent our ownership share in these unconsolidated affiliates as follows: Texas Express Pipeline, 35%; Front Range Pipeline, 33.3%; and Seaway Pipeline, 50%.
(2) Shippers on the Texas Express Pipeline and Front Range Pipeline have experienced periods where transportation volumes have been less than committed volumes due to ethane rejection in the supply basins served by these pipelines.
(3) Shipper transportation volumes on ATEX have been negatively impacted by changes in producer drilling programs, including the timing of new production well start-ups in the Marcellus and Utica Shale developments.
(4) Shippers on Seaway's Longhaul System have experienced periods where transportation volumes have been less than committed volumes due to lower regional crude oil price spreads between the Cushing hub and Gulf Coast destination markets. In general, as price spreads decrease, there is less incentive to ship crude oil to the Gulf Coast. The primary reason for the lower spreads is a narrowing of the price differential between WTI and Brent prices.

Distributable cash flow

The following table presents a reconciliation of non-GAAP distributable cash flow to GAAP net cash flows provided by operating activities for the periods indicated (dollars in millions):

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Distributable cash flow	$ 5,607.3	$ 4,078.6	$ 3,750.4
Adjustments to reconcile distributable cash flow to net cash flows provided by operating activities:			
Add sustaining capital expenditures reflected in distributable cash flow	272.6	369.0	291.7
Subtract cash proceeds from asset sales and insurance recoveries reflected in distributable cash flow	(1,608.6)	(145.3)	(280.6)
Add losses or subtract gains from monetization of interest rate derivative instruments accounted for as cash flow hedges	--	(27.6)	168.8
Net effect of changes in operating accounts not reflected in distributable cash flow	(323.3)	(108.2)	(97.6)
Other, net	54.4	(4.3)	32.8
Net cash flows provided by operating activities	$ 4,002.4	$ 4,162.2	$ 3,865.5

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, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

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

- the derivative instrument functions effectively as a hedge of the underlying risk;
- the derivative instrument is not closed out in advance of its expected term; and
- the hedged forecasted transaction occurs within the expected time period.

We routinely review the effectiveness of our derivative instrument portfolios in light of current market conditions. 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 hedging activities.

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, 2015 (volume measures as noted):

Derivative Purpose	Volume (1) Current (2)	Volume (1) Long-Term (2)	Accounting Treatment
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	9.1	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	2.1	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	2.4	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	10.7	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	28.7	0.4	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	42.2	0.1	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	2.7	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.8	0.1	Cash flow hedge
Refined products inventory management activities (MMBbls)	1.3	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	15.0	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	17.6	n/a	Cash flow hedge
Crude oil inventory management activities (MMBbls)	0.7	n/a	Fair value hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	48.2	8.2	Mark-to-market
NGL risk management activities (MMBbls) (4)	1.8	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	11.8	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2017, January 2017 and March 2018, respectively.
(3) Current and long-term volumes include 24.3 Bcf and 2.1 Bcf, respectively, 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, 2015, 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 forward contracts and derivative instruments.

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

- 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 forward contracts and derivative instruments.

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our natural gas marketing portfolio at the dates indicated (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2014	Portfolio Fair Value at December 31, 2015	Portfolio Fair Value at January 29, 2016
Fair value assuming no change in underlying commodity prices	*Asset (Liability)*	$ 5.8	$ 0.1	$ (1.0)
Fair value assuming 10% increase in underlying commodity prices	*Asset (Liability)*	2.4	(3.7)	(4.5)
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	9.2	3.9	2.4

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our NGL marketing, refined products marketing and octane enhancement portfolios at the dates indicated (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2014	Portfolio Fair Value at December 31, 2015	Portfolio Fair Value at January 29, 2016
Fair value assuming no change in underlying commodity prices	*Asset*	$ 57.8	$ 69.6	$ 39.5
Fair value assuming 10% increase in underlying commodity prices	*Asset*	47.5	41.7	18.6
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	68.2	97.4	60.3

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our crude oil marketing portfolio at the dates indicated (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2014	Portfolio Fair Value at December 31, 2015	Portfolio Fair Value at January 29, 2016
Fair value assuming no change in underlying commodity prices	*Asset*	$ 15.6	$ 42.9	$ 29.9
Fair value assuming 10% increase in underlying commodity prices	*Asset*	6.5	25.9	4.9
Fair value assuming 10% decrease in underlying commodity prices	*Asset*	24.7	60.0	54.9

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.

With respect to the tabular data below, each portfolio's estimated fair value at a given date is based on a number of factors, including the number and types of derivatives outstanding at that date, the notional value of the swaps and associated interest rates.

Interest rate swaps

Interest rate swaps exchange the stated interest rate paid on a notional amount of existing debt for the fixed or floating interest rate stipulated in the derivative instrument. The following table summarizes our portfolio of interest rate swaps at December 31, 2015 (dollars in millions):

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes OO	10 fixed-to-floating swaps	$750.0	5/2015 to 5/2018	1.65% to 0.82%	Fair value hedge

The following table shows the effect of hypothetical price movements (a sensitivity analysis) on the estimated fair value of our interest rate swap portfolio at the dates indicated (dollars in millions):

Scenario	Resulting Classification	Portfolio Fair Value at December 31, 2014	Portfolio Fair Value at December 31, 2015	Portfolio Fair Value at January 29, 2016
Fair value assuming no change in underlying interest rates	*Asset (Liability)*	$ --	$ (0.5)	$ 6.2
Fair value assuming 10% increase in underlying interest rates	*Asset (Liability)*	--	(2.6)	4.8
Fair value assuming 10% decrease in underlying interest rates	*Asset*	--	1.7	7.7

Product Purchase Commitments

We have long and short-term purchase commitments for natural gas, NGLs, crude oil, petrochemicals and refined products. The purchase prices that we are obligated to pay under these contracts are based on market prices at the time we take delivery of the volumes. For additional information regarding these commitments, see 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.

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, (ii) W. Randall Fowler, our general partner's President, and (iii) Bryan F. Bulawa, our general partner's 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 Messrs. Fowler and Bulawa represent our principal financial officers. Based on this evaluation, as of the end of the period covered by this annual report, Messrs. Teague, Fowler and Bulawa 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

As a result of our acquisition of EFS Midstream effective July 1, 2015, the Company is evaluating and implementing changes to processes, policies and other components of its internal control over financial reporting with respect to the consolidation of EFS Midstream's operations into the Company's financial statements. Management continues to be engaged in efforts to evaluate the effectiveness of our internal control procedures and the design of those control procedures relating to EFS Midstream. Due to the recent nature of this business combination, we have excluded EFS Midstream from the scope of management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2015.

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 2015, 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, Fowler and Bulawa 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).

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING AS OF DECEMBER 31, 2015

The management of Enterprise Products Partners L.P. and its consolidated subsidiaries, including its Chief Executive Officer, 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, 2015. 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, 2015, 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.

We acquired EFS Midstream on July 1, 2015. Due to the recent nature of this business combination, it was not practical from a timing or resource standpoint for us to conduct a thorough assessment of EFS Midstream's internal control over financial reporting prior to December 31, 2015. As a result, we excluded EFS Midstream from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2015. We are in the process of implementing our internal control structure over the operations of EFS Midstream and expect that this effort will be completed during 2016. EFS Midstream accounted for approximately 0.44% of our consolidated revenues for the year ended December 31, 2015 and 2.98% of our total consolidated assets at December 31, 2015.

Deloitte & Touche LLP has issued its attestation report regarding our internal control over financial reporting. That report is included within this 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 February 26, 2016.

/s/ A. James Teague

Name: A. James Teague
Title: Chief Executive Officer
of Enterprise Products Holdings LLC

/s/ W. Randall Fowler

Name: W. Randall Fowler
Title: President
of Enterprise Products Holdings LLC

/s/ Bryan F. Bulawa

Name: Bryan F. Bulawa
Title: Chief Financial Officer
of Enterprise Products Holdings LLC

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As described in *Management's Annual Report on Internal Controls Over Financial Reporting as of December 31, 2015*, management excluded from its assessment the internal control over financial reporting of EFS Midstream, which was acquired on July 1, 2015 and whose financial statements constitute approximately 0.44% of the Company's consolidated revenues for the year ended December 31, 2015 and 2.98% of its total consolidated assets as of December 31, 2015. Accordingly, our audit did not include the internal control over financial reporting of EFS Midstream. 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, 2015. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the related statements of consolidated operations, comprehensive income, cash flows, and equity as of and for the year ended December 31, 2015 of the Company and our report dated February 26, 2016 expressed an unqualified opinion on those financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

Item 9B. ***Other Information*.**

None.

PART III

Item 10. ***Directors, Executive Officers and Partnership Governance*.**

Partnership Management

General
On January 5, 2016, Dan Duncan LLC, the sole member of Enterprise GP, re-elected the following individuals to the Board of Directors (the "Board") of Enterprise GP: Carin M. Barth, Dr. F. Christian Flach, W. Randall Fowler, James T. Hackett, Charles E. McMahen, William C. Montgomery, Richard S. Snell, A. James Teague and Randa Duncan Williams. In addition, Richard H. Bachmann was elected to join the Board. Ms. Duncan Williams continues to serve as the non-executive Chairman of the Board, and Mr. Bachmann now serves as the non-executive Vice Chairman of the Board. In addition, effective as of January 5, 2016, Mr. Fowler's role as an officer of Enterprise GP was changed from Chief Administrative Officer ("CAO") to President.

The following individuals (who served as directors prior to January 5, 2016) were not re-elected to the Board: Thurmon M. Andress and E. William Barnett.

In March 2015, Michael A. Creel, a director and the Chief Executive Officer ("CEO") of Enterprise GP, announced his intention to retire at the end of calendar year 2015. The Board then elected Mr. Teague to succeed Mr. Creel as CEO upon Mr. Creel's retirement. On December 31, 2015, Mr. Creel's retirement became effective and Mr. Teague (who previously served as the Chief Operating Officer ("COO") of Enterprise GP) succeeded Mr. Creel as CEO. In connection with his retirement, Mr. Creel also resigned from the Board effective as of December 31, 2015.

In April 2014, Larry J. Casey and Edwin C. Smith were appointed as "advisory directors" for Enterprise GP and continue to serve in that capacity. In addition, O.S. Andras continues to serve as an "honorary director." 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).

Marquard & Bahls ("M&B"), a German corporation and ultimate parent of Oiltanking, is entitled to designate a nominee for election to the Board (the "M&B Designee") as long as M&B and its affiliates beneficially own at least 27,403,676 of our common units issued to M&B and its affiliates in connection with the Oiltanking acquisition. Dr. Flach serves on the Board as the current M&B Designee. In the event that the M&B Designee becomes unable or unwilling to, or for another reason ceases to, serve as a member of the Board while M&B is entitled to maintain the M&B Designee, M&B may designate another person reasonably acceptable to the Board as a replacement.

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 2015 were Ms. Duncan Williams and Messrs. Creel, Fowler and Teague. Effective December 31, 2015, Mr. Creel retired.

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.

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 CEO) and Mr. Fowler (as President). The purpose of the Office of the Chairman is for the group to serve collectively as a liaison to the Board and senior management with respect to, and to provide the Chairman, Vice-Chairman, President, and CEO 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 CEO and the President, the Vice Chairman of the Board and other Board members 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 the Company in connection with our disclosure controls and procedures and internal control over financial reporting.

In his role as President, Mr. Fowler is one of two principal financial officers of Enterprise GP 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, governmental affairs, and public relations and (iii) providing the required certifications as a co-principal financial officer of the Company (together with the Chief Financial Officer, or "CFO") in connection with our disclosure controls and procedures and internal control over financial reporting.

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 CEO and the President, the Chairman of the Board and other Board members to review our company's strategic direction.

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 February 26, 2016. 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)	54	Director and Chairman of the Board
Richard H. Bachmann (1)	63	Director and Vice Chairman of the Board
A. James Teague (1,6)	70	Director and CEO
W. Randall Fowler (1,6)	59	Director and President
Carin M. Barth (2)	53	Director
Dr. F. Christian Flach	48	Director
James T. Hackett (2,3)	62	Director
Charles E. McMahen (4,5)	76	Director
William C. Montgomery (4)	54	Director
Richard S. Snell (4)	73	Director
Graham W. Bacon (6)	52	Executive Vice President
William Ordemann (6)	56	Executive Vice President
G. R. Cardillo (6)	58	Group Senior Vice President
Craig W. Murray (6)	68	Group Senior Vice President and General Counsel
R. Daniel Boss (6)	40	Senior Vice President
Bryan F. Bulawa (6)	46	Senior Vice President and CFO
Michael J. Knesek (6)	61	Senior Vice President, Controller 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) 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 also serves as a member of Enterprise GP's Governance Committee. 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 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, 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.

Richard H. Bachmann

Mr. Bachmann was elected a director and Vice Chairman of the Board of Enterprise GP in January 2016. He previously served as a director of Enterprise GP from November 2010 through April 2014. He served as an Executive Vice President of Holdings GP from April 2005 to November 2010 and as a director of Holdings GP from February 2006 to November 2010. He served as Chief Legal Officer and Secretary of Holdings GP from April 2005 to May 2010. Mr. Bachmann served as Executive Vice President and Chief Legal Officer of 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 was elected President and CEO of EPCO in May 2010 and has served as a director since January 1999. He previously served as Secretary of EPCO from May 1999 to May 2010 and as a Group Vice Chairman of EPCO from December 2007 to May 2010. Mr. Bachmann served as a director of DEP Holdings, LLC ("DEP GP") 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, upon Mr. Creel's retirement, and has been a director of Enterprise GP since November 2010. Mr. Teague previously served as the 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 served as an Executive Vice President of EPGP from November 1999 to November 2010 and as one of its directors 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 an Executive Vice President and the Chief Commercial Officer of DEP GP from July 2008 until September 2011. He also 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.

W. Randall Fowler

Mr. Fowler was elected President of Enterprise GP in January 2016 and has been a director of Enterprise GP since September 2011. He previously served as CAO of Enterprise GP from April 2015 to January 2016. Mr. Fowler served as an Executive Vice President and CFO of Enterprise GP from November 2010 to March 2015, and as an Executive Vice President and CFO of EPGP from August 2007 to November 2010. Mr. Fowler served as a Senior Vice President and Treasurer of EPGP from February 2005 to August 2007 and was a director of EPGP from February 2006 to May 2010. 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 served as President and CEO of DEP GP from April 2010 to 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 DEP GP from October 2006 to August 2007. Mr. Fowler also previously served as a director of Holdings GP from February 2006 to May 2010. He also served as a Senior Vice President and CFO of Holdings GP from August 2005 to August 2007.

Mr. Fowler, a Certified Public Accountant (inactive), joined Enterprise as Director of Investor Relations in January 1999. He serves as Chairman of the Board of the Master Limited Partnership Association (formerly the National Association of Publicly Traded Partnerships) and 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 and is a member of its Governance Committee. She 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: Bill Barrett Corporation; Black Stone Minerals, L.P., where she is Chair of the Audit Committee; Strategic Growth Bancorp Incorporated (a privately held bank holding company located in El Paso), where she is Chair of the Audit Committee; and Capital Bank, SSB, an affiliate of Strategic Growth Bancorp. Additionally, she is Chairman of the Investment Advisory Committee for the Endowment at Texas Tech University, a Trustee 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: Western Refining Inc., where she was Chair of the Audit Committee from March 2006 to January 2016, the 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 Chief Financial Officer of the U.S. Department of Housing and Urban Development from 2004 to 2005.

Dr. F. Christian Flach
Dr. Flach was elected a director of Enterprise GP in October 2014 in connection with the Oiltanking acquisition (as the M&B designee). He previously served as Chairman of the Board of Oiltanking GP from March 2014 to October 2014. He has served as Chief Executive Officer of M&B since 2011 and is also a Member of its Executive Board. Dr. Flach began working for M&B in May 1996 and has served in various roles for the organization and its affiliates, including General Manager of M&B and Mabanaft, the oil trading business within M&B; lawyer for Oiltanking GmbH; Managing Director of Oiltanking GmbH; Director of Corporate Affairs at M&B; Director of Human Resources at M&B and Managing Director of Mabanaft.

James T. Hackett
Mr. Hackett was elected as a director of Enterprise GP in April 2014 and serves as Chairman of its Governance Committee. Mr. Hackett is a partner with Riverstone Holdings LLC, a private energy investment firm. He served as Executive Chairman of the board of directors of Anadarko Petroleum Corporation ("Anadarko"), one of the world's largest independent oil and natural gas exploration and production companies, from 2012 to 2013 after serving as its CEO since 2003 and Chairman of the Board since 2006. He also served as Anadarko's President from 2003 to 2010. Mr. Hackett is an advisory director of Cameron International Corporation and a consultant to Fluor Corporation. He also serves on the board of a closed investment fund traded on the London Stock Exchange called Riverstone Energy Ltd. as well as Sierra Oil & Gas (a Mexican portfolio company of Riverstone). Mr. Hackett is a former director of Halliburton Company and Bunge Ltd. and the former Chairman of the Board of the Federal Reserve Bank of Dallas. He is the immediate past Chairman of the National Petroleum Council and a member of the Society of Petroleum Engineers and the Baylor College of Medicine Board of Trustees. Mr. Hackett is also a former adjunct Professor of Finance at Rice University.

Charles E. McMahen
Mr. McMahen was elected a director of Enterprise GP in November 2010 and serves as Chairman of its Audit and Conflicts Committee. He served as a director of Holdings GP from August 2005 to November 2010. Mr. McMahen served as Vice Chairman of Compass Bank from March 1999 until December 2003 and served as Vice Chairman of Compass Bancshares from April 2001 until his retirement in December 2003. Mr. McMahen also served as Chairman and CEO of Compass Banks of Texas from March 1990 until March 1999. Mr. McMahen has served as a director of Compass Bancshares, and its successor, BBVA Compass Bank (a wholly owned subsidiary of BBVA), since 2001. He also serves as a director for BBVA Compass Bancshares, Inc. (a wholly owned subsidiary of BBVA and a bank holding company for BBVA's North American banking operations). Mr. McMahen serves on the Audit Committee for BBVA Compass Bancshares, Inc. and as Chairman of its Risk Committee. 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 in October 2015 and is a member of its Audit and Conflicts Committee. He has served as a Managing Director and 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. 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. He also serves on the board of Apache Corporation. Mr. Montgomery has chaired 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.

Richard S. Snell
Mr. Snell, a Certified Public Accountant, was elected a director of Enterprise GP in September 2011 and serves on its Audit and Conflicts Committee. He previously served as a director of DEP GP from January 2010 until September 2011. Mr. Snell also served 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. He is Of Counsel with the law firm of Thompson & Knight LLP, having been with the firm since 2000. Prior to his position with Thompson & Knight LLP, he worked as an attorney for the Snell & Smith, P.C. law firm from its founding in 1993 until 2000.

Graham W. Bacon
Mr. Bacon was elected an Executive Vice President (Operations and Engineering) of Enterprise GP in October 2015. He previously served as a 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. He holds a Bachelor's degree in Chemical Engineering from Texas A&M University and a Master's degree in Business Administration from Oklahoma City University.

William Ordemann
Mr. Ordemann was elected an Executive Vice President (Commercial) of Enterprise GP in October 2015, having previously served as a Group Senior Vice President from April 2012 to October 2015. He served as Executive Vice President of Enterprise GP from August 2007 to April 2012. He served as COO of EPGP from August 2007 until September 2010 and as its Executive Vice President from August 2007 to November 2010. He was also elected an Executive Vice President of DEP GP in August 2007 and served in such role until September 2011. 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 joined Enterprise in connection with its purchase of certain midstream energy assets from affiliates of Shell Oil Company in 1999. He also served as a director of Oiltanking GP from October 2014 until February 2015.

G. R. Cardillo
Mr. Cardillo was elected a Group Senior Vice President of Enterprise GP in February 2015. He previously served as Senior Vice President (Propylene and Marine) from February 2011 to February 2015. Mr. Cardillo served as a Vice President of EPGP from November 2004 to November 2010 and of Enterprise GP from November 2010 to February 2011. He assumed leadership of our marine services operations in July 2010. Mr. Cardillo has been an integral part of our petrochemicals management team since joining Enterprise in 2002 and assumed leadership of this commercial function in June 2008. Mr. Cardillo joined Enterprise in connection with its purchase of certain petrochemical storage and propylene fractionation assets from affiliates of Ultramar Diamond Shamrock Corp. and Koch Industries Inc. ("Diamond Koch") in 2002. From 2000 to 2002, Mr. Cardillo served as a Vice President in charge of propylene commercial activities for Diamond Koch.

Craig W. Murray
Mr. Murray was elected a Group Senior Vice President and General Counsel of Enterprise GP in January 2015. Prior to joining Enterprise, Mr. Murray served as a Partner at Vinson & Elkins LLP in Houston, Texas from April 1976 to December 2014, with his most recent role being that of a Senior Partner. At Vinson & Elkins, Mr. Murray focused primarily on corporate and energy-related finance matters, with a special emphasis on structured finance, asset securitization, and project finance transactions. Mr. Murray's experience in energy finance has involved oil and gas properties in Texas, Louisiana, and all major oil and gas producing states, as well as offshore properties in the Gulf of Mexico. Mr. Murray is a member of the American Bar Association, Texas Bar Association and Houston Bar Association and has been recognized in numerous publications for his professional accomplishments.

R. Daniel Boss
Mr. Boss was elected a Senior Vice President of Enterprise GP in March 2015 with responsibility over our regulated business. He 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.

Bryan F. Bulawa
Mr. Bulawa was elected a Senior Vice President and CFO of Enterprise GP in April 2015. Mr. Bulawa also served as Senior Vice President and Treasurer of Enterprise GP from October 2009 to March 2015, Senior Vice President, CFO and Treasurer of DEP GP from April 2010 to September 2011 and as a Director of DEP GP from February 2011 to September 2011. He previously served as Senior Vice President and Treasurer of EPGP from October 2009 to November 2010, as Senior Vice President and Treasurer of DEP GP from October 2009 to April 2010, and as Vice President and Treasurer of EPGP from July 2007 to October 2009.

He has also served as Senior Vice President and CFO of EPCO since April 2015, having previously served as Senior Vice President and Treasurer from May 2010 to March 2015. Mr. Bulawa also served as Chairman of the Board for Oiltanking GP from October 2014 to February 2015. Prior to joining Enterprise, Mr. Bulawa spent 13 years at Scotia Capital, where he last served as director of the firm's U.S. Energy Corporate Finance and Distribution group.

Michael J. Knesek
Mr. Knesek, a Certified Public Accountant, was elected Senior Vice President, Controller and Principal Accounting Officer of Enterprise GP in November 2010. From February 2005 to November 2010, Mr. Knesek served as Senior Vice President of EPGP, having previously served as a Vice President of EPGP since August 2000. Mr. Knesek served as the Principal Accounting Officer and Controller of DEP GP from September 2006 to September 2011. He served as the Principal Accounting Officer and Controller of Holdings GP from August 2005 to November 2010 and served in the same capacity for EPGP from August 2000 to November 2010. He also served as Senior Vice President of DEP GP from September 2006 to September 2011. Mr. Knesek has been the Controller of EPCO since 1990 and currently serves as one of its Senior Vice Presidents.

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.

Four 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, over 12 years of experience with our midstream assets, including finance, accounting and investor relations and, for over the last nine years, as a member of our executive management team; and

- for Mr. Bachmann, over 30 years of experience with our midstream assets, including legal, regulatory, contracts and mergers and acquisitions and, for over the last ten years, as a member of either EPCO's or our executive management teams.

Our six 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 Dr. Flach, executive management of an international energy supply, trading and logistics company;

- 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; and

- for Mr. Snell, professional experience involving complex legal and accounting matters.

As advisory directors, 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.

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. Hackett, McMahen, Montgomery and Snell are independent directors under the NYSE rules.

Because we are a limited partnership and meet the definition of a "controlled company" under the listing standards of the NYSE, we are not required to comply with certain NYSE rules. In particular, we are not required to comply with Section 303A.01 of the NYSE Listed Company Manual, which would require that the Board of our general partner be comprised of a majority of independent directors. Currently, five of the ten 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 President, CEO, CFO, Principal Accounting Officer and senior financial and other managers to prevent wrongdoing and to promote honest and ethical conduct, including ethical handling of actual and apparent conflicts of interest, compliance with applicable laws, rules and regulations, full, fair, accurate, timely and understandable disclosure in public communications, and prompt internal reporting of violations of the code (and thus accountability for adherence to the code). Employees are required to 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 three 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. McMahen, Montgomery and Snell, all of whom are independent directors, free from any relationship with us or any of our subsidiaries that would interfere with the exercise of independent judgment. The Board has affirmatively determined that Mr. McMahen satisfies the definition of "*Audit Committee Financial Expert*" as defined in Item 407(d)(5) of Regulation S-K promulgated by the SEC.

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, health and safety policies, procedures, programs and initiatives, and related matters. In accordance with its charter, the Governance Committee shall be composed of not less than three members, at least a majority of whom shall be independent directors. Currently, the Governance Committee is comprised of 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.

Investor Access to Corporate Governance Information
We provide investors access to information relating to our governance procedures and principles, including the Code of Conduct, Governance Guidelines, the Audit and Conflicts Committee and Governance Committee charters, 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.

NYSE Corporate Governance Listing Standards
On March 9, 2015, Mr. Creel 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 (877) 888-0002.

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 2015.

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 all of 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 the years ended December 31, 2015, 2014 and 2013 for our CEO, CFOs, and the three other most highly compensated executive officers of our general partner. Collectively, these individuals were our "named executive officers" for 2015.

Name and Principal Position	Year	Cash Salary ($)	Cash Bonus ($) (1)	Unit Awards ($) (2)	All Other Compensation ($) (3)	Total ($)
A. James Teague (4)	2015	$ 793,750	$ 1,800,000	$ 4,108,628	$ 550,701	$ 7,253,079
(CEO and former COO)	2014	753,788	1,750,000	4,691,680	10,515,870	17,711,338
	2013	690,150	1,750,000	4,123,342	489,233	7,052,725
Michael A. Creel (4)	2015	793,750	--	4,108,628	553,826	5,456,204
(Former CEO)	2014	775,000	1,750,000	4,691,680	10,389,474	17,606,154
	2013	775,000	1,750,000	4,123,342	575,115	7,223,457
W. Randall Fowler (5)	2015	459,375	581,250	2,042,400	285,691	3,368,716
(President and	2014	427,973	562,500	2,230,200	4,011,435	7,232,108
former CFO and CAO)	2013	418,144	562,500	2,141,625	302,824	3,425,093
Bryan F. Bulawa (5)	2015	306,000	233,750	810,152	122,214	1,472,116
(Senior Vice President and CFO)						
William Ordemann	2015	447,400	340,000	1,198,715	184,258	2,170,373
(Executive Vice President)	2014	433,400	327,000	1,321,600	2,694,010	4,776,010
	2013	425,150	400,000	1,142,200	234,962	2,202,312
Graham W. Bacon	2015	320,021	275,000	1,021,200	155,071	1,771,292
(Executive Vice President)						

(1) Amounts represent discretionary annual cash awards accrued with respect to the years presented. Cash awards are paid in February of the following year (e.g., the 2015 cash bonus amounts were paid in February 2016).

(2) Amounts represent our estimated share of the aggregate grant date fair value of equity-based awards granted during each year presented.

(3) Amounts include (i) contributions in connection with funded, qualified, defined contribution retirement plans, (ii) quarterly distributions paid on incentive plan awards, (iii) the imputed value of life insurance premiums paid on behalf of the officer, (iv) employee retention payments and (v) other amounts.

(4) Mr. Teague was elected CEO effective January 1, 2016 upon the retirement of our former CEO, Mr. Creel, on December 31, 2015. Mr. Teague served as our COO during 2015.

(5) Mr. Bulawa was elected CFO effective April 1, 2015, succeeding Mr. Fowler as CFO.

The following table presents the components of "All Other Compensation" for each named executive officer for the year ended December 31, 2015:

	Contributions Under Funded, Qualified, Defined Contribution Retirement Plans	Quarterly Distributions Paid On Incentive Plan Awards (1)	Life Insurance Premiums	Other	Total All Other Compensation
A. James Teague	$ 28,531	$ 502,979	$ 13,596	$ 5,595	$ 550,701
Michael A. Creel	28,531	513,373	4,356	7,566	553,826
W. Randall Fowler	21,863	256,005	2,129	5,694	285,691
Bryan F. Bulawa	19,401	96,265	842	5,706	122,214
William Ordemann	31,800	143,953	2,838	5,667	184,258
Graham W. Bacon	30,447	114,690	1,506	8,428	155,071

(1) Reflects aggregate cash payments made to named executive officer in connection with (i) distributions paid on restricted common units and (ii) distribution equivalent rights associated with phantom unit awards.

Compensation Discussion and Analysis

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 equity-based long-term incentive plans of EPCO. The EPCO Trustees control EPCO and provide recommendations with respect to the compensation of our CEO, which for purposes of this Compensation Discussion and Analysis includes the historical compensation of both Mr. Creel and Mr. Teague (including his former service as COO), and our President. As described further below, the Audit and Conflicts Committee of our general partner has ultimate decision-making authority with respect to compensation for each of our President and our CEO, and our President and our CEO have ultimate decision-making authority with respect to compensation for our other named executive officers. The elements of compensation for each named executive officer are not subject to approvals by the Board or the Audit and Conflicts Committee of our general partner, except in the case of compensation paid to each of our President and our CEO (as described below). Neither EPCO nor our general partner has a separate compensation committee; however, equity-based awards granted under EPCO's long-term incentive plans to officers of Enterprise GP (including our named executive officers) are approved by the Audit and Conflicts Committee.

As discussed below, the elements of EPCO's compensation program, along with EPCO's other incentives (e.g., benefits, work environment and career development), are intended to provide a total rewards package to employees. The 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. The compensation package is designed to reward contributions by employees in support of the business strategies of EPCO and its affiliates at both our partnership and individual levels. With respect to the three years ended December 31, 2015, EPCO's compensation package for named executive officers did not include any elements based on targeted performance-related criteria.

The primary elements of EPCO's compensation program for named executive officers are a combination of annual cash and long-term equity-based incentive compensation. For the three years ended December 31, 2015, the primary elements of compensation consisted of annual cash base salary, discretionary annual cash bonus awards, equity-based awards under long-term incentive arrangements and other compensation, including very limited perquisites. For the year ended December 31, 2014, other compensation for Messrs. Creel, Teague, Fowler and Ordemann also included a cash retention bonus (as described below).

In order to assist our President and our CEO, the EPCO Trustees and the Audit and Conflicts Committee with compensation decisions, EPCO's senior vice president of Human Resources formulates preliminary compensation recommendations for each of the named executive officers. With respect to compensation to be paid to our President and our CEO, the EPCO Trustees consider such preliminary recommendations and make revisions, if appropriate.

Afterwards, EPCO's senior vice president of Human Resources presents the compensation recommendations for our President and our CEO to the Audit and Conflicts Committee, which consider the recommendations and then make a final determination regarding compensation of these individuals. In making their final determination, the Audit and Conflicts Committee may discuss the recommendations with EPCO's senior vice president of Human Resources, request to discuss the recommendations with EPCO's compensation consultant, and/or retain its own compensation consultant.

With respect to compensation to be paid to the remaining named executive officers other than our President and our CEO, the President and the CEO consider the preliminary recommendations of EPCO's senior vice president of Human Resources and make revisions, if appropriate. The President and the CEO make a final determination regarding compensation of these named executive officers.

In making these compensation decisions, EPCO considers market data for determining relevant compensation levels and compensation program elements through the review of and, in certain cases, participation in, relevant compensation surveys and reports. These surveys and reports are conducted and prepared by a third party compensation consultant. In 2015, EPCO engaged Meridian Compensation Partners, LLC (the "Consultant") to complete a detailed review of executive compensation relative to our industry. In connection with this review, the Consultant provided comparative market data on compensation practices and programs for executive level positions based on an analysis of industry competitors and other large companies. The market data for industry competitors included information from Anadarko Petroleum Corporation; CenterPoint Energy, Inc.; Dominion Resources, Inc.; Enbridge Energy Partners, L.P.; Energy Transfer Partners, L.P.; 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. The market data for other large companies included 56 entities across multiple industries, including well-known companies such as Caterpillar Inc.; Target Corporation; and Honeywell International Inc., among others.

Neither we, nor EPCO, which engages the Consultant, are aware of the specific data of the companies included in the Consultant's proprietary database for specific positions. EPCO uses the information provided in the Consultant's analysis to gauge whether compensation levels reported by the Consultant and the general ranges of compensation for EPCO employees in similar positions are comparable, but that comparison is only a factor taken into consideration and may or may not impact compensation of our named executive officers, for which our Audit 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.

The Audit and Conflicts Committee, our President, our CEO and the EPCO Trustees do not use any formula or specific performance-based criteria in determining the compensation of our named executive officers for services they perform for us; rather, the Audit and Conflicts Committee or our President and our CEO (as applicable) and the EPCO Trustees determine an appropriate level and mix of compensation on a case-by-case basis. Further, there is no established policy or target for the allocation between either cash and non-cash or short-term and long-term incentive compensation. However, some considerations that the Audit 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 the EPCO Trustees also consider individual performance, levels of responsibility and value to the organization. All compensation determinations are subjective and discretionary and, as noted above, subject to the ultimate decision-making authority of the Audit and Conflicts Committee or our President and our CEO (as applicable), except for equity-based awards under EPCO's long-term incentive plans, as discussed below.

We believe that the absence of specific performance-based criteria associated with our cash compensation and equity-based awards, and the long-term nature of our equity-based awards, has the effect of discouraging excessive risk taking by our executive officers in order to reach certain targets. Further, the practice of making compensation decisions on a case-by-case basis permits consideration of flexible criteria, including current overall market conditions.

Changes in the base salaries of our named executive officers during the three years ending December 31, 2015 were largely budget-driven and made consistent relative to increases in the base salaries of our other executive officers.

The discretionary cash bonus awards paid to each of our named executive officers were determined by consultation, as appropriate, among the EPCO Trustees, our President, our CEO and EPCO's senior vice president of Human Resources, subject to final determination by the Audit and Conflicts Committee (in the case of our President's and our CEO's cash bonus awards) and our President and our CEO (in the case of cash bonus awards to be paid to our other named executive officers). These cash bonus awards, in combination with annual base salaries, are intended to yield competitive total cash compensation levels for the named executive officers and drive performance in support of our business strategies, as well as the performance of other EPCO affiliates for which the named executive officers may perform services. It is EPCO's general policy to pay these awards in February of the following year. The discretionary cash bonuses reflect the Audit and Conflicts Committee's (with respect to our President and our CEO) and our President's and our CEO's (with respect to the other named executive officers) general consideration of our financial performance for those periods, without any weight or formula given to any specific financial performance measures, as well as their subjective judgment of each named executive officer's general contributions in connection with our performance, again without any weight or formula given to any specific individual contribution or accomplishments. The levels of cash bonuses were also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

Equity-based awards granted to our named executive officers under EPCO's long-term incentive plans were determined by consultation, as appropriate, among the EPCO Trustees, our President, our CEO and EPCO's senior vice president of Human Resources, and were approved by the Audit and Conflicts Committee. 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 the Audit and Conflicts Committee's (with respect to our President and our CEO) and our President's and our CEO's (with respect to the other named executive officers) general consideration of our financial performance for those periods, without any weight or formula given to any specific financial performance measures, as well as their subjective judgment of each named executive officer's general contributions in connection with our performance, again without any weight or formula given to any specific individual contribution or accomplishments. The levels of equity-based awards were also based on the level and position of such named executive officers and the relative compensation paid to our other executive officers.

EPCO expects to continue its policy of paying for limited perquisites attributable to our named executive officers. EPCO also makes matching contributions under its defined contribution plans for the benefit of our named executive officers in the same manner as it does for other EPCO employees.

EPCO does not offer our named executive officers a defined benefit pension plan. Also, none of our named executive officers had nonqualified deferred compensation during the three years ended December 31, 2015.

In the fourth quarter of 2014, Messrs. Creel, Fowler, Teague and Ordemann received cash employee retention payments of $10 million, $5 million, $10 million and $2.5 million, respectively, less applicable tax withholdings. These payments were made in connection with retention agreements that EPCO entered into with each named executive officer in the fourth quarter of 2010. We were allocated all or a portion of these payments based on the amount of time each officer spent on our affairs since entering into these agreements. The purpose of the retention agreements was to reinforce and encourage the continued dedication of such officers to EPCO and us as a member of our executive management team. In order to qualify for the retention payments, each executive officer was required to complete 48 months of continuous employment with EPCO from the effective date of each officer's retention agreement.

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	2015	100%	--	100%
	2014	100%	--	100%
	2013	100%	--	100%
Michael A. Creel	2015	100%	--	100%
	2014	100%	--	100%
	2013	100%	--	100%
W. Randall Fowler	2015	75%	25%	100%
	2014	75%	25%	100%
	2013	75%	25%	100%
Bryan F. Bulawa	2015	85%	15%	100%
William Ordemann	2015	100%	--	100%
	2014	100%	--	100%
	2013	100%	--	100%
Graham W. Bacon	2015	100%	--	100%

In conclusion, we believe that each of the base salary, discretionary cash bonus awards, long-term incentive awards and retention agreements, as applicable, fit our overall compensation objectives, as well as those of EPCO, and are designed to avoid risks that are likely to conflict with our risk management policies.

Grants of Equity-Based Awards in Fiscal Year 2015

The following table presents information concerning each 2015 grant of an equity-based award to a named executive officer for which we will be allocated our pro rata share of the related cost under the ASA.

Named Executive Officer	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards			Exercise or Base Price of Option Awards ($/Unit)	Grant Date Fair Value of Unit Awards ($) (1,2)
		Threshold (#)	Target (#)	Maximum (#)		
Phantom unit awards:						
A. James Teague	2/18/15	--	120,700	--	--	$ 4,108,628
Michael A. Creel	2/18/15	--	120,700	--	--	4,108,628
W. Randall Fowler	2/18/15	--	80,000	--	--	2,042,400
Bryan F. Bulawa	2/18/15	--	28,000	--	--	810,152
William Ordemann	2/18/15	--	30,000	--	--	1,021,200
	8/03/15	--	6,500	--	--	177,515
Graham W. Bacon	2/18/15	--	30,000	--	--	1,021,200

(1) Amounts presented reflect that portion of grant date fair value allocable to us based on the average percentage of time each named executive officer spent on our consolidated businesses during 2015. Based on current allocations, we estimate that the compensation expense we record for Messrs. Teague, Fowler, Bulawa, Ordemann and Bacon with respect to these phantom unit awards will approximate the grant date fair value amounts over the vesting period. Since Mr. Creel retired on December 31, 2015, his February 2015 phantom unit award was fully expensed through December 31, 2015, which was the end of his service period.

(2) The closing price per unit of our common units on February 18, 2015 and August 3, 2015 was $34.04 and $27.31, respectively.

In connection with the phantom unit awards noted above, each named executive officer was granted distribution equivalent rights ("DERs," see description below). The phantom unit awards and the associated DERs granted to the named executive officers in 2015 were made under the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) (the "2008 Plan").

Grant date fair value amounts presented in the preceding table are based on certain assumptions and considerations made by management. 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.

Summary of Long-Term Incentive Arrangements Underlying 2015 Award Grants

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 unit options, restricted common units, phantom units, DERs, unit appreciation rights ("UARs") and other unit-based awards or substitute awards. As of December 31, 2015, no UARs have been granted to employees under 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. The fair value of a phantom unit award is based on the market price per unit of our common units on the date of grant. For financial statement purposes, compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures.

A DER entitles the recipient to non-forfeitable cash payments equal to the product of the number of phantom unit awards outstanding for the recipient (on the date of record for each quarterly cash distribution to common unitholders) and the cash distribution per common unit paid by us to our common unitholders. The following cash payments were made to the named executive officers in connection with their outstanding phantom unit awards and tandem DERs during the year ended December 31, 2015: Mr. Teague, $311,548; Mr. Creel, $311,548; Mr. Fowler, $201,450; Mr. Bulawa, $67,811; Mr. Ordemann, $85,703; and Mr. Bacon, $73,400. Since our phantom unit awards are expected to result in the issuance of common units at vesting, cash payments made in connection with the DERs are charged to partners' equity.

Equity-Based Awards Outstanding at December 31, 2015

The following information summarizes each named executive officer's long-term incentive awards outstanding at the close of business on December 31, 2015.

		Option Awards				Unit Awards	
Named Executive Officer	**Vesting Date**	**Number of Units Underlying Options Exercisable (#)**	**Number of Units Underlying Options Unexercisable (#)**	**Option Exercise Price ($/Unit)**	**Option Expiration Date**	**Number of Units That Have Not Vested (#)** (1)	**Market Value of Units That Have Not Vested ($)** (2)
Restricted common unit awards: (3)							
A. James Teague	Various (1)	--	--	--	--	104,600	$ 2,675,668
W. Randall Fowler	Various (1)	--	--	--	--	75,000	1,918,500
Bryan F. Bulawa	Various (1)	--	--	--	--	24,372	623,436
William Ordemann	Various (1)	--	--	--	--	30,000	767,400
Graham W. Bacon	Various (1)	--	--	--	--	22,750	581,945
Phantom unit awards: (4)							
A. James Teague	Various (1)	--	--	--	--	227,200	5,811,776
W. Randall Fowler	Various (1)	--	--	--	--	147,500	3,773,050
Bryan F. Bulawa	Various (1)	--	--	--	--	49,974	1,278,335
William Ordemann	Various (1)	--	--	--	--	66,500	1,701,070
Graham W. Bacon	Various (1)	--	--	--	--	54,000	1,381,320

(1) Amounts represent the total number of awards outstanding for each named executive officer.
(2) Amounts derived by multiplying the total number of restricted common unit or phantom unit awards outstanding for each named executive officer by the closing price of our common units at December 31, 2015 (the last trading day of 2015) of $25.58 per unit.
(3) Of the 256,722 non-vested restricted common unit awards presented in the table, 169,748 vest in 2016 and 86,974 vest in 2017.
(4) Of the 545,174 non-vested phantom unit awards presented in the table, 157,126 vest in 2016 and 157,124 vest in each of the years 2017 and 2018 and 73,800 vest in 2019.

In accordance with our existing retirement guidelines, the vesting of Mr. Creel's equity-based awards was accelerated to December 31, 2015. At December 31, 2015, he had 108,200 restricted common unit awards and 227,200 phantom unit awards outstanding. Based on the closing price of our common units on December 31, 2015, the market value of his restricted common unit awards and phantom unit awards outstanding on that date was approximately $2.8 million and $5.8 million, respectively. The compensation expense associated with these awards was fully recognized as of December 31, 2015, which was the last day of his service period. The vesting of these awards was processed in February 2016.

Option Exercises and Units Vested

The following table presents the exercise of unit options by and vesting of restricted common unit and phantom unit awards to our named executive officers during the year ended December 31, 2015. These amounts are presented on a gross basis and do not reflect any allocation of compensation to other entities under the ASA.

	Option Awards		Unit Awards	
Named Executive Officer	**Number of Units Acquired on Exercise (#)** (1)	**Value Realized on Exercise ($)** (2)	**Number of Units Acquired on Vesting (#)** (1)	**Value Realized on Vesting ($)** (3)
A. James Teague:				
Option awards	120,000	$ 2,238,600		
Restricted common unit awards			90,500	$ 3,044,939
Phantom unit awards			35,500	1,199,545
Michael A. Creel:				
Option awards	180,000	3,455,100		
Restricted common unit awards			103,900	3,494,509
Phantom unit awards			35,500	1,199,545
W. Randall Fowler:				
Option awards	120,000	2,238,600		
Restricted common unit awards			72,000	2,421,600
Phantom unit awards			22,500	760,275
Bryan F. Bulawa:				
Option awards	40,000	568,100		
Restricted common unit awards			23,350	785,343
Phantom unit awards			7,326	247,546
William Ordemann:				
Option awards	120,000	1,989,000		
Restricted common unit awards			35,000	1,176,650
Phantom unit awards			10,000	337,900
Graham W. Bacon:				
Restricted common unit awards			18,750	630,923
Phantom unit awards			8,000	270,320

(1) Represents the gross number of common units acquired upon exercise of unit options and vesting of restricted common unit and phantom unit awards before adjustments for applicable tax withholdings.

(2) Amount determined by multiplying the number of gross common units acquired upon exercise of unit options by the difference between the closing price of our common units on the date of exercise and the exercise price.

(3) Amount determined by multiplying the gross number of restricted common unit and phantom unit awards that vested during 2015 by the closing price of our common units on the date of vesting.

EPCO's long-term incentive plans provide for the issuance of non-qualified incentive options denominated in our common units. There were no unit option awards outstanding at December 31, 2015. All such awards were exercised during 2015.

Potential Payments Upon Termination or Change-in-Control

Messrs. Teague, Fowler, Bulawa, Ordemann and Bacon do not 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.

Vesting of equity-based awards under EPCO's long-term incentive plans are subject to acceleration upon a qualifying termination, including termination after a change of control of our general partner. Qualifying termination under such awards generally means a termination as an employee of EPCO or an affiliated group member (i) upon death, (ii) a qualifying long-term disability, (iii) a qualifying retirement, or (iv) within one year after a change of control (as defined), other than a termination for cause (as defined) or termination by such person that is not a qualifying termination for good reason (as defined). A "change of control" under these award agreements is generally defined to mean that the descendants, heirs and/or legatees, and/or trusts (including, without limitation, one or more voting trusts) established for the benefit of Dan L. Duncan's descendants, heirs and/or legatees, 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, our CEO, our President, and the Audit and Conflicts Committee of our general partner.

In light of the foregoing, the Board has reviewed and discussed with management the Compensation Discussion and Analysis set forth above and determined that it be included in this annual report for the year ended December 31, 2015.

Submitted by: Randa Duncan Williams
Richard H. Bachmann
A. James Teague
W. Randall Fowler
Carin M. Barth
Dr. F. Christian Flach
James T. Hackett
Charles E. McMahen
William C. Montgomery
Richard S. Snell

Notwithstanding anything to the contrary set forth in any previous filings under the Securities Act, as amended, or the Securities Exchange Act, as amended, that incorporate future filings, including this annual report, in whole or in part, the foregoing Compensation Committee Report shall not be incorporated by reference into any such filings.

Compensation Committee Interlocks and Insider Participation

None of the directors or executive officers of our general partner served as members of the compensation committee of another entity that has or had an executive officer who served as a member of our Board during the year ended December 31, 2015. As previously noted, we do not have a separate compensation committee. As described in Compensation Discussion and Analysis, decisions regarding the compensation of our named executive officers are made, as applicable, by EPCO, our CEO, our President, and the Audit and Conflicts Committee of our general partner.

Director Compensation

Neither we nor our general partner provide any additional compensation to employees of EPCO who serve as directors of our general partner. Likewise, Dr. Flach does not receive any compensation for his services.

For calendar year 2015, the independent voting directors of our general partner were compensated as follows: (i) 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 approximately $85,000, (ii) if the individual served as a chairman of the Audit and Conflicts Committee, then he received an additional $20,000 annual cash retainer; and (iii) if the individual served as a chairman of the Governance Committee, then he received an additional $15,000 annual cash retainer. The cash portion of the compensation described above (i) was payable quarterly and (ii) was prorated for the number of days in a calendar quarter that an individual serves as an independent voting director and/or as a chairman of the Audit and Conflicts Committee and/or the Governance Committee.

Our advisory directors, Messrs. Casey and Smith, each received a $150,000 annual cash retainer in 2015. As an honorary director, O.S. Andras received a $20,000 annual cash retainer.

The director compensation program for calendar year 2016 is expected to be the same as the one presented above for 2015.

We bear all costs attributable to the compensation of directors of our general partner. The following table summarizes compensation paid to the independent directors of our general partner during the year ended December 31, 2015:

Name	Fees Earned or Paid in Cash ($)	Value of Equity-Based Awards ($)	Total ($)
Thurmon M. Andress (1)	$ 85,000	$ 85,012	$ 170,012
E. William Barnett (2)	100,000	85,012	185,012
Carin M. Barth (3)	21,250	--	21,250
Larry J. Casey (4)	150,000	--	150,000
James T. Hackett	85,000	85,012	170,012
Charles E. McMahen (5)	105,000	85,012	190,012
William C. Montgomery (3)	21,250	--	21,250
Edwin E. Smith (4)	150,000	--	150,000
Richard S. Snell	85,000	85,012	170,012
O.S. Andras (6)	20,000	--	20,000

(1) Mr. Andress served as a member of Audit and Conflicts Committee in 2015. He was not re-elected to the Board for 2016.
(2) Mr. Barnett served as chairman of the Governance Committee in 2015. He was not re-elected to the Board for 2016.
(3) Ms. Barth and Mr. Montgomery were elected to the Board in October 2015; therefore, their cash compensation for 2015 was prorated. In addition, due to the timing of their election in late 2015, neither Ms. Barth nor Mr. Montgomery received a grant of common units in 2015.
(4) Messrs. Casey and Smith serve as advisory directors.
(5) Mr. McMahen serves as chairman of the Audit and Conflicts Committee.
(6) Mr. Andras serves as an honorary director.

Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.*

Security Ownership of Certain Beneficial Owners

The following table sets forth certain information as of January 31, 2016, regarding each person known by Enterprise GP to beneficially own more than 5% of our limited partner units:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common units	Randa Duncan Williams 1100 Louisiana Street, 10th Floor Houston, Texas 77002	680,989,923 (1)	33.7%

(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 Item 12.

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 our general partner. 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 table sets forth certain information regarding the beneficial ownership of our common units, including restricted common units, as of January 31, 2016 by (i) our named executive officers for 2015; (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 January 31, 2016	Amount and Nature Of Beneficial Ownership	Percent of Class
Randa Duncan Williams:	Director and Chairman of the Board		
Units controlled by DD LLC Voting Trust:			
Through DFI GP Holdings L.P.		81,688,412	4.0%
Through Dan Duncan LLC		41,762	*
Units controlled by EPCO Voting Trust:			
Through EPCO		1,046,612	*
Through EPCO Investments, LLC		33,708,091	1.7%
Through EPCO Holdings, Inc.		550,428,808	27.3%
Units controlled by Alkek and Williams, Ltd.		326,000	*
Units controlled by family trusts (1)		13,737,108	*
Units owned personally (2)		13,130	*
Total for Randa Duncan Williams		680,989,923	33.7%
Richard H. Bachmann (3)	Director and Vice Chairman of the Board	1,362,801	*
A. James Teague (4,5)	Director and CEO	1,977,468	*
W. Randall Fowler (4,6)	Director and President	1,283,583	*
Carin M. Barth	Director	--	--
Dr. F. Christian Flach	Director	--	--
James T. Hackett (7)	Director	251,158	*
Charles E. McMahen	Director	87,554	*
William C. Montgomery	Director	26,500	*
Richard S. Snell (8)	Director	45,482	*
William Ordemann (4,9)	Executive Vice President	913,380	*
Graham W. Bacon (4,10)	Executive Vice President	159,084	*
Bryan F. Bulawa (4,11)	Senior Vice President and CFO	132,210	*
Michael A. Creel (4,12)	Former CEO	1,803,274	*
All directors and executive officers (including all named executive officers) of Enterprise GP, as a group (18 individuals in total) (13)		689,888,905	34.2%

** Represents a beneficial ownership of less than 1% of class*

(1) The number of common units presented for Ms. Duncan Williams includes (i) 10,406,489 common units held by family trusts for which she serves as a trustee but has disclaimed beneficial ownership (except to the extent of her pecuniary interest therein) and (ii) 3,330,619 common units held by a trust for which she and/or members of her immediate family are beneficiaries but for which she does not serve as a trustee and therefore disclaims beneficial ownership.

(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.

(3) The number of common units presented for Mr. Bachmann includes 9,588 common units held by his spouse.

(4) These individuals are named executive officers for the year ended December 31, 2015.

(5) The number of common units presented for Mr. Teague includes (i) 53,000 common units held by a trust and (ii) 469,493 common units held by Mr. Teague's spouse. In addition, the number of common units presented for Mr. Teague includes an aggregate 65,675 phantom units that vested in February 2016, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

(6) The number of common units presented for Mr. Fowler includes 500,000 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 42,500 phantom units that vested in February 2016, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

(7) The number of common units presented for Mr. Hackett includes (i) 9,661 common units held by family trusts and (ii) 25,000 common units held by a family limited partnership.

(8) The number of common units presented for Mr. Snell includes 2,956 common units held by his spouse.

(9) The number of common units presented for Mr. Ordemann includes an aggregate 17,500 phantom units that vested in February 2016, 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 15,500 phantom units that vested in February 2016, 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. Bulawa includes an aggregate 14,326 phantom units that vested in February 2016, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.
(12) Mr. Creel retired effective December 31, 2015.
(13) Cumulatively, this group's beneficial ownership amount includes an aggregate 187,976 phantom units that vested in February 2016, which resulted in the issuance of an equal number of common units before adjustment for any withholding taxes.

Privately held affiliates of EPCO (together with their respective subsidiaries) have pledged 118,000,000 of our common units that they own as security under such affiliates' credit facilities. These credit facilities include customary provisions regarding potential events of default. As a result, a change in ownership of these units could result if an event of default ultimately occurred.

Equity Ownership Guidelines

In order to further align the interests and actions of our general partner's directors and executive officers with our long-term interests and those of our general partner and other unitholders, the Board has adopted and approved certain equity ownership guidelines for our general partner's directors and executive officers. Under these guidelines:

- each non-management director of our general partner is required to own 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

The following table sets forth certain information as of December 31, 2015 regarding the long-term incentive plans of EPCO under which our common units are authorized for issuance. For additional information regarding our equity-based compensation, see Note 13 of the Notes to Consolidated Financial Statements included under Part II, Item 8 of this annual report.

Plan Category	Number of Units to Be Issued Upon Exercise of Outstanding Common Unit Options	Weighted-Average Exercise Price of Outstanding Common Unit Options	Number of Units Remaining Available For Future Issuance Under Equity Compensation Plans (excluding securities reflected in column (a))
	(a)	(b)	(c)
Equity compensation plans approved by unitholders:			
1998 Plan (1)	--	--	3,073,703
2008 Plan (2)	--	--	16,669,007
Equity compensation plans not approved by unitholders:			
None	--	--	--
Total for equity compensation plans	--	--	19,742,710

(1) The total number of common units authorized for issuance under the 1998 Plan was 14,000,000 common units.
(2) At December 31, 2015, the total number of common units authorized for issuance under the 2008 Plan was 30,000,000 common units. This amount increased by 5,000,000 common units on January 1, 2016 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.

The Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") provides for awards of our common units and other rights to our non-management directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted common units, phantom units and DERs.

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.

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 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.

As of January 5, 2016, the Audit and Conflicts Committee was comprised of three independent directors: Charles E. McMahen, William C. Montgomery and Richard S. 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, 2015.

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.

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;
- 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. McMahen, Montgomery 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 is an employee of EPCO that performs services on our behalf. This individual does not serve as an executive officer of Enterprise GP, EPCO or any of their respective affiliates, and his compensation and other terms of employment are determined on a basis consistent with EPCO's human resources policies. This individual earned total compensation from EPCO of approximately $200 thousand for 2015.

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 (or in) each of the years presented, as applicable:

	For the Year Ended December 31,	
	2015 (1)	**2014**
Audit fees	$ 5,322,800	$ 4,679,000

(1) Audit fees for 2015 include a one-time $900,000 charge for the audit of the financial statements of our Offshore Business. This special audit was required in connection with the sale of this business in July 2015. The audit fee was reimbursed to us by the buyer.

As presented in the preceding table, "Audit Fees" represent amounts billed for each year in connection with (i) the audit of our annual financial statements and internal controls over financial reporting, (ii) the review of our quarterly financial statements filed on Form 10-Q, (iii) standalone 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.

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 our principal accountant from management.

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 Public Company Accounting Oversight Board.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules*.**

(a) 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).
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).

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 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).

3.7 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).

3.8 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).

3.9 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).

3.10 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).

3.11 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).

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 10, 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 Fifth 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 4.2 to Form 8-K filed March 3, 2005).

4.8 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).

4.9 Eighth Supplemental Indenture, dated as of July 18, 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 July 19, 2006).

4.10 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).

4.11 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).

4.12 Eleventh Supplemental Indenture, dated as of September 4, 2007, 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 September 5, 2007).

4.13 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).

4.14 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).

4.15 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).

4.16 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).

4.17 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).

4.18 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).

4.19 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).

4.20 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).

4.21 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).

4.22 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).

4.23 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).

4.24 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).

4.25 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).

4.26 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 4.8 to Form 10-K filed March 31, 2003).

4.27 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).

4.28 Form of Global Note representing $250.0 million principal amount of 5.00% Series B Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 4, 2005).

4.29 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).

4.30 Form of Junior Subordinated Note, including Guarantee (incorporated by reference to Exhibit 4.2 to Form 8-K filed July 19, 2006).

4.31 Form of Global Note representing $800.0 million principal amount of 6.30% Senior Notes due 2017 with attached Guarantee (incorporated by reference to Exhibit 4.38 to Form 10-Q filed November 9, 2007).

4.32 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 4.4 to Form 8-K filed April 3, 2008).

4.33 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 4.3 to Form 8-K filed October 5, 2009).

4.34 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 4.3 to Form 8-K filed October 5, 2009).

4.35 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 4.6 to Form 8-K filed

October 28, 2009).

4.36 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 4.7 to Form 8-K filed October 28, 2009).

4.37 Form of Global Note representing $285.8 million principal amount of 7.000% Junior Subordinated Notes due 2067 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 8-K filed October 28, 2009).

4.38 Form of Global Note representing $400.0 million principal amount of 3.70% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed May 20, 2010).

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 4.4 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 4.4 to Form 8-K filed May 20, 2010).

4.41 Form of Global Note representing $750.0 million principal amount of 3.20% Senior Notes due 2016 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 13, 2011).

4.42 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 4.4 to Form 8-K filed January 13, 2011).

4.43 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 4.4 to Form 8-K filed August 24, 2011).

4.44 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 4.4 to Form 8-K filed August 24, 2011).

4.45 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 4.25 to Form 10-Q filed May 10, 2012).

4.46 Form of Global Note representing $650.0 million principal amount of 1.25% Senior Notes due 2015 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 13, 2012).

4.47 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 4.4 to Form 8-K filed August 13, 2012).

4.48 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 4.4 to Form 8-K filed March 18, 2013).

4.49 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 4.4 to Form 8-K filed March 18, 2013).

4.50 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 4.4 to Form 8-K filed February 12, 2014).

4.51 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 4.4 to Form 8-K filed February 12, 2014).

4.52 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 4.5 to Form 8-K filed October 14, 2014).

4.53 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 4.5 to Form 8-K filed October 14, 2014).

4.54 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 4.5 to Form 8-K filed October 14, 2014).

4.55 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 4.5 to Form 8-K filed October 14, 2014).

4.56 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 4.5 to Form 8-K filed May 7, 2015).

4.57 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 4.5 to Form 8-K filed May 7, 2015).

4.58 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 4.5 to Form 8-K filed May 7, 2015).

4.59 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).

4.60 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).

4.61 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).

4.62 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).

4.63 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).

4.64 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).

4.65 Second 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).

4.66 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).

4.67 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).

4.68 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).

4.69	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).
4.70	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).
4.71	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 on March 1, 2010).
4.72	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).
4.73	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).
4.74	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).
4.75	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).
4.76	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 on March 1, 2010).
4.77	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 on 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 Option Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.11 to Form 10-Q filed August 9, 2010).
10.5***	Form of Employee Restricted Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan (incorporated by reference to Exhibit 10.13 to Form 10-Q filed August 9, 2010).
10.6***	Form of Employee Phantom Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 18, 2015 (incorporated by reference to Exhibit 10.18 to Form 10-K filed March 3, 2014).

10.7*** Amendment Letter to Restricted Unit and Phantom Unit Grant Awards under the Enterprise Products 1998 Long-Term Incentive Plan and/or the 2008 Enterprise Products Long-Term Incentive Plan for awards issued before February 18, 2015 (incorporated by reference to Exhibit 10.7 to Form 10-K filed on March 2, 2015).

10.8*** Form of Employee Phantom Unit Grant Award under the 2008 Enterprise Products Long-Term Incentive Plan for awards issued on or after February 18, 2015 (incorporated by reference to Exhibit 10.8 to Form 10-K filed on March 2, 2015).

10.9 Distribution Waiver Agreement, dated as of November 22, 2010, by and among Enterprise Products Partners L.P., EPCO Holdings, Inc. and the EPD Unitholder named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 23, 2010).

10.10 Revolving Credit Agreement, dated as of September 7, 2011, among Enterprise Products Operating LLC, Canadian Enterprise Gas Products, Ltd, the Lenders party thereto, Wells Fargo Bank National Association, as Administrative Agent, The Royal Bank of Scotland PLC, Mizuho Corporate Bank, Ltd. and The Bank of Nova Scotia, as Co-syndication Agents and JPMorgan Chase Bank, N.A. and Barclays Bank PLC, as Co-Documentation Agents (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 8, 2011).

10.11 Guaranty Agreement, dated as of September 7, 2011, by and among Enterprise Products Partners L.P. and Enterprise Products Operating LLC in favor of Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 8, 2011).

10.12 First Amendment dated as of June 19, 2013 to Revolving Credit Agreement dated as of September 7, 2011, among Enterprise Products Operating LLC, Canadian Enterprise Gas Products, Ltd., Wells Fargo Bank, National Association, as administrative agent for each of the lenders that is a signatory or which becomes a signatory to the Credit Agreement, the Lenders party thereto, Citibank, N.A., DNB Bank ASA, New York Branch, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd. and The Royal Bank of Scotland Plc, as Co-Syndication Agents, and The Bank of Nova Scotia, SunTrust Bank, The Bank of Tokyo-Mitsubishi UFJ, Ltd., UBS Securities LLC and Royal Bank of Canada, as Co-Documentation Agents, and Wells Fargo Securities, LLC, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Corporate Bank, Ltd., RBS Securities Inc., Scotia Capital, SunTrust Robinson Humphrey, Inc., and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.3 to Form 8-K filed on June 20, 2013).

10.13 Second Amendment dated as of September 16, 2015 to Revolving Credit Agreement dated as of September 7, 2011, as amended by First Amendment to Revolving Credit Agreement dated as of June 19, 2013, among Enterprise Products Operating LLC, Wells Fargo Bank, National Association, as Administrative Agent, the Lenders and Issuing Banks party thereto, 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 Royal Bank of Canada, The Bank of Nova Scotia, SunTrust Bank and UBS Securities LLC, as Co-Documentation Agents, and Wells Fargo Securities, LLC, Citigroup Global Markets Inc., DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd., The Bank of Tokyo-Mitsubishi UFJ, Ltd., RBC Capital Markets, The Bank of Nova Scotia, SunTrust Robinson Humphrey, Inc., and UBS Securities LLC, as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.2 to Form 8-K filed September 16, 2015).

10.14 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 on February 13, 2015).

10.15 364-Day Revolving Credit Agreement, dated as of September 30, 2014, among Enterprise Products Operating LLC, the Lenders party thereto, Citibank, N.A., as Administrative Agent, certain financial institutions from time to time named therein, as Co-Documentation Agents and Citibank, N.A. as Sole Lead Arranger and Sole Book Runner (incorporated by reference to Exhibit 10.1 to Form 8-K filed on October 1, 2014).

10.16 Guaranty Agreement, dated as of September 30, 2014, 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 on October 1, 2014).
10.17	First Amendment to 364-Day Revolving Credit Agreement dated as of September 16, 2015, by and among Enterprise Products Operating LLC, Citibank, N.A., as Administrative Agent, the Lenders party thereto, Wells Fargo Bank, National Association, 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 Royal Bank of Canada, The Bank of Nova Scotia, SunTrust Bank and UBS Securities LLC, as Co-Documentation Agents, and Citigroup Global Markets Inc., Wells Fargo Securities, LLC, DNB Markets, Inc., J.P. Morgan Securities LLC, Mizuho Bank, Ltd., The Bank of Tokyo-Mitsubishi UFJ, Ltd., RBC Capital Markets, The Bank of Nova Scotia, SunTrust Robinson Humphrey, Inc. and UBS Securities LLC, as Joint Lead Arrangers and Joint Book Runners (incorporated by reference to Exhibit 10.1 to Form 8-K filed September 16, 2015).
10.18	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 on October 1, 2014).
10.19	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 on November 12, 2014).
10.20	Equity Distribution Agreement, dated August 10, 2015, 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, Mitsubishi UFJ Securities (USA), Inc., Mizuho Securities USA Inc., Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC, Scotia Capital (USA) Inc., SMBC Nikko Securities America, Inc., SunTrust Robinson Humphrey, Inc., UBS Securities LLC, USCA Securities LLC and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 1.1 to Form 8-K filed August 10, 2015).
10.21***#	Retirement and Release Agreement, dated effective as of December 31, 2015, by and among Michael A. Creel and Enterprise Products Company.
12.1#	Computation of ratio of earnings to fixed charges for each of the years ended December 31, 2015, 2014, 2013, 2012 and 2011.
21.1#	List of consolidated subsidiaries as of February 1, 2016.
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, 2015.
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, 2015.
31.3#	Sarbanes-Oxley Section 302 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2015.
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, 2015.
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, 2015.
32.3#	Sarbanes-Oxley Section 906 certification of Bryan F. Bulawa for Enterprise Products Partners L.P.'s annual report on Form 10-K for the year ended December 31, 2015.
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.

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 February 26, 2016.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products Holdings LLC, as General Partner

By: */s/ Michael J. Knesek*
Name: Michael J. Knesek
Title: Senior Vice President, Controller and Principal Accounting Officer of the General Partner

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 February 26, 2016.

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 and President
/s/ Bryan F. Bulawa Bryan F. Bulawa	Senior Vice President and Chief Financial Officer
/s/ Michael J. Knesek Michael J. Knesek	Senior Vice President, Controller and Principal Accounting Officer
/s/ Carin M. Barth Carin M. Barth	Director
/s/ Dr. F. Christian Flach Dr. F. Christian Flach	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/ Richard S. Snell Richard S. Snell	Director

Item 8. Financial Statements and Supplementary Data.

ENTERPRISE PRODUCTS PARTNERS L.P.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

	Page No.
Report of Independent Registered Public Accounting Firm	F-2
Consolidated Balance Sheets as of December 31, 2015 and 2014	F-3
Statements of Consolidated Operations for the Years Ended December 31, 2015, 2014 and 2013	F-4
Statements of Consolidated Comprehensive Income for the Years Ended December 31, 2015, 2014 and 2013	F-5
Statements of Consolidated Cash Flows for the Years Ended December 31, 2015, 2014 and 2013	F-6
Statements of Consolidated Equity for the Years Ended December 31, 2015, 2014 and 2013	F-7
Notes to Consolidated Financial Statements	
Note 1 – Partnership Operations, Organization and Basis of Presentation	F-8
Note 2 – Summary of Significant Accounting Policies	F-9
Note 3 – Revenue Recognition	F-16
Note 4 – Inventories	F-20
Note 5 – Property, Plant and Equipment	F-21
Note 6 – Investments in Unconsolidated Affiliates	F-23
Note 7 – Intangible Assets and Goodwill	F-27
Note 8 – Debt Obligations	F-31
Note 9 – Equity and Distributions	F-35
Note 10 – Business Segments	F-40
Note 11 – Earnings Per Unit	F-45
Note 12 – Business Combinations	F-46
Note 13 – Equity-Based Awards	F-50
Note 14 – Derivative Instruments, Hedging Activities and Fair Value Measurements	F-53
Note 15 – Related Party Transactions	F-62
Note 16 – Provision for Income Taxes	F-64
Note 17 – Commitments and Contingencies	F-65
Note 18 – Significant Risks and Uncertainties	F-71
Note 19 – Supplemental Cash Flow Information	F-73
Note 20 – Quarterly Financial Information (Unaudited)	F-74
Note 21 – Condensed Consolidating Financial Information	F-75

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

We have audited the accompanying consolidated balance sheets of Enterprise Products Partners L.P. and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related statements of consolidated operations, comprehensive income, cash flows, and equity for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enterprise Products Partners L.P. and subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2016, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2016

ENTERPRISE PRODUCTS PARTNERS L.P.
CONSOLIDATED BALANCE SHEETS
(Dollars in millions)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 19.0	$ 74.4
Restricted cash	15.9	--
Accounts receivable – trade, net of allowance for doubtful accounts of $12.1 at December 31, 2015 and $13.9 at December 31, 2014	2,569.9	3,823.0
Accounts receivable – related parties	1.2	2.8
Inventories	1,038.1	1,014.2
Derivative assets (see Note 14)	258.6	226.0
Prepaid and other current assets	410.3	350.3
Total current assets	4,313.0	5,490.7
Property, plant and equipment, net	32,034.7	29,881.6
Investments in unconsolidated affiliates	2,628.5	3,042.0
Intangible assets, net of accumulated amortization of $1,235.8 at December 31, 2015 and $1,246.3 at December 31, 2014 (see Note 7)	4,037.2	4,302.1
Goodwill (see Note 7)	5,745.2	4,300.2
Other assets	193.4	184.4
Total assets	$ 48,952.0	$ 47,201.0
LIABILITIES AND EQUITY		
Current liabilities:		
Current maturities of debt (see Note 8)	$ 1,863.9	$ 2,206.4
Accounts payable – trade	860.1	773.8
Accounts payable – related parties	84.1	118.9
Accrued product payables	2,484.4	3,853.3
Accrued liability related to EFS Midstream acquisition (see Note 12)	993.2	--
Accrued interest	352.1	335.5
Other current liabilities	528.8	585.8
Total current liabilities	7,166.6	7,873.7
Long-term debt (see Note 8)	20,826.7	19,157.4
Deferred tax liabilities	46.1	66.6
Other long-term liabilities	411.5	411.1
Commitments and contingencies (see Note 17)		
Equity: (see Note 9)		
Partners' equity:		
Limited partners:		
Common units (2,012,553,024 units outstanding at December 31, 2015 and 1,937,324,817 units outstanding at December 31, 2014)	20,514.3	18,304.8
Accumulated other comprehensive loss	(219.2)	(241.6)
Total partners' equity	20,295.1	18,063.2
Noncontrolling interests	206.0	1,629.0
Total equity	20,501.1	19,692.2
Total liabilities and equity	$ 48,952.0	$ 47,201.0

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED OPERATIONS
(Dollars in millions, except per unit amounts)

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Revenues:			
Third parties	$ 26,955.6	$ 47,879.7	$ 47,661.1
Related parties	72.3	71.5	65.9
Total revenues (see Note 10)	27,027.9	47,951.2	47,727.0
Costs and expenses:			
Operating costs and expenses:			
Third parties	22,588.2	43,228.4	43,300.8
Related parties	1,080.5	992.1	937.9
Total operating costs and expenses	23,668.7	44,220.5	44,238.7
General and administrative costs:			
Third parties	78.5	83.7	74.0
Related parties	114.1	130.8	114.3
Total general and administrative costs	192.6	214.5	188.3
Total costs and expenses (see Note 10)	23,861.3	44,435.0	44,427.0
Equity in income of unconsolidated affiliates	373.6	259.5	167.3
Operating income	3,540.2	3,775.7	3,467.3
Other income (expense):			
Interest expense	(961.8)	(921.0)	(802.5)
Change in fair value of Liquidity Option Agreement (see Note 17)	(25.4)	--	--
Other, net	2.9	1.9	(0.2)
Total other expense, net	(984.3)	(919.1)	(802.7)
Income before income taxes	2,555.9	2,856.6	2,664.6
Benefit from (provision for) income taxes (see Note 16)	2.5	(23.1)	(57.5)
Net income	2,558.4	2,833.5	2,607.1
Net income attributable to noncontrolling interests (see Note 9)	(37.2)	(46.1)	(10.2)
Net income attributable to limited partners	$ 2,521.2	$ 2,787.4	$ 2,596.9
Earnings per unit: (see Note 11)			
Basic earnings per unit	$ 1.28	$ 1.51	$ 1.45
Diluted earnings per unit	$ 1.26	$ 1.47	$ 1.41

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME
(Dollars in millions)

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Net income	$ 2,558.4	$ 2,833.5	$ 2,607.1
Other comprehensive income (loss):			
Cash flow hedges:			
Commodity derivative instruments:			
Changes in fair value of cash flow hedges	214.9	161.3	(46.9)
Reclassification of losses (gains) to net income	(228.2)	(76.7)	22.1
Interest rate derivative instruments:			
Changes in fair value of cash flow hedges	--	--	6.6
Reclassification of losses to net income	35.3	32.4	29.2
Total cash flow hedges	22.0	117.0	11.0
Other	0.4	0.4	0.4
Total other comprehensive income	22.4	117.4	11.4
Comprehensive income	2,580.8	2,950.9	2,618.5
Comprehensive income attributable to noncontrolling interests	(37.2)	(46.1)	(10.2)
Comprehensive income attributable to limited partners	$ 2,543.6	$ 2,904.8	$ 2,608.3

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in millions)

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Operating activities:			
Net income	$ 2,558.4	$ 2,833.5	$ 2,607.1
Reconciliation of net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	1,516.0	1,360.5	1,217.6
Non-cash asset impairment charges (see Note 14)	162.6	34.0	92.6
Equity in income of unconsolidated affiliates	(373.6)	(259.5)	(167.3)
Distributions received from unconsolidated affiliates	462.1	375.1	251.6
Net losses (gains) attributable to asset sales and insurance recoveries (see Note 19)	15.6	(102.1)	(83.3)
Gains on early extinguishment of debt	(1.6)	--	--
Deferred income tax expense (benefit)	(20.6)	6.1	37.9
Changes in fair value of Liquidity Option Agreement	25.4	--	--
Changes in fair market value of derivative instruments	(18.4)	30.6	1.4
Net effect of changes in operating accounts (see Note 19)	(323.3)	(108.2)	(97.6)
Other operating activities	(0.2)	(7.8)	5.5
Net cash flows provided by operating activities	4,002.4	4,162.2	3,865.5
Investing activities:			
Capital expenditures	(3,830.7)	(2,892.9)	(3,408.2)
Contributions in aid of construction costs	19.1	28.9	26.0
Decrease (increase) in restricted cash	(15.9)	65.6	(61.3)
Cash used for business combinations, net of cash received (see Note 12)	(1,056.5)	(2,416.8)	--
Investments in unconsolidated affiliates	(162.6)	(722.4)	(1,094.1)
Proceeds from asset sales and insurance recoveries (see Note 19)	1,608.6	145.3	280.6
Other investing activities	(3.8)	(5.6)	(0.5)
Cash used in investing activities	(3,441.8)	(5,797.9)	(4,257.5)
Financing activities:			
Borrowings under debt agreements	21,081.1	18,361.1	13,852.8
Repayments of debt	(19,867.2)	(14,341.1)	(12,680.6)
Debt issuance costs	(24.0)	(41.2)	(23.7)
Monetization of interest rate derivative instruments (see Note 14)	--	27.6	(168.8)
Cash distributions paid to limited partners (see Note 9)	(2,943.7)	(2,638.1)	(2,400.3)
Cash payments made in connection with distribution equivalent rights	(7.7)	(3.7)	--
Cash distributions paid to noncontrolling interests (see Note 9)	(48.0)	(48.6)	(8.9)
Cash contributions from noncontrolling interests (see Note 9)	54.0	4.0	115.4
Net cash proceeds from the issuance of common units	1,188.6	388.8	1,792.0
Other financing activities	(49.1)	(55.6)	(45.1)
Cash provided by (used in) financing activities	(616.0)	1,653.2	432.8
Net change in cash and cash equivalents	(55.4)	17.5	40.8
Cash and cash equivalents, January 1	74.4	56.9	16.1
Cash and cash equivalents, December 31	$ 19.0	$ 74.4	$ 56.9

See Notes to Consolidated Financial Statements.

ENTERPRISE PRODUCTS PARTNERS L.P.
STATEMENTS OF CONSOLIDATED EQUITY
(See Note 9 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, 2012	$ 13,558.1	$ (370.4)	$ 108.3	$ 13,296.0
Net income	2,596.9	--	10.2	2,607.1
Cash distributions paid to limited partners	(2,400.3)	--	--	(2,400.3)
Cash distributions paid to noncontrolling interests	--	--	(8.9)	(8.9)
Cash contributions from noncontrolling interests	--	--	115.4	115.4
Net cash proceeds from the issuance of common units	1,792.0	--	--	1,792.0
Amortization of fair value of equity-based awards	72.4	--	--	72.4
Cash flow hedges	--	11.0	--	11.0
Other	(45.3)	0.4	0.6	(44.3)
Balance, December 31, 2013	15,573.8	(359.0)	225.6	15,440.4
Net income	2,787.4	--	46.1	2,833.5
Cash distributions paid to limited partners	(2,638.1)	--	--	(2,638.1)
Cash payments made in connection with distribution equivalent rights	(3.7)	--	--	(3.7)
Cash distributions paid to noncontrolling interests	--	--	(48.6)	(48.6)
Cash contributions from noncontrolling interests	--	--	4.0	4.0
Common units issued and noncontrolling interests acquired in connection with Step 1 of Oiltanking acquisition	2,171.5	--	1,397.2	3,568.7
Net cash proceeds from the issuance of common units	388.8	--	--	388.8
Amortization of fair value of equity-based awards	81.8	--	5.2	87.0
Cash flow hedges	--	117.0	--	117.0
Other	(56.7)	0.4	(0.5)	(56.8)
Balance, December 31, 2014	18,304.8	(241.6)	1,629.0	19,692.2
Net income	2,521.2	--	37.2	2,558.4
Cash distributions paid to limited partners	(2,943.7)	--	--	(2,943.7)
Cash payments made in connection with distribution equivalent rights	(7.7)	--	--	(7.7)
Cash distributions paid to noncontrolling interests	--	--	(48.0)	(48.0)
Cash contributions from noncontrolling interests	--	--	54.0	54.0
Common units issued in connection with Step 2 of Oiltanking acquisition	1,408.7	--	(1,408.7)	--
Removal of noncontrolling interests in connection with sale of Offshore Business	--	--	(62.1)	(62.1)
Net cash proceeds from the issuance of common units	1,188.6	--	--	1,188.6
Amortization of fair value of equity-based awards	92.4	--	--	92.4
Cash flow hedges	--	22.0	--	22.0
Other	(50.0)	0.4	4.6	(45.0)
Balance, December 31, 2015	$ 20,514.3	$ (219.2)	$ 206.0	$ 20,501.1

See 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. 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 President 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 Administrative Officer of EPCO. EPCO, together with its privately held affiliates, owned approximately 33.6% of our limited partner interests at December 31, 2015.

References to "Oiltanking" and "Oiltanking GP" mean Oiltanking Partners, L.P. and OTLP GP, LLC, the general partner of Oiltanking, respectively. In October 2014, we acquired approximately 65.9% of the limited partner interests of Oiltanking, all of the member interests of Oiltanking GP and the incentive distribution rights ("IDRs") held by Oiltanking GP from Oiltanking Holding Americas, Inc. ("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 acquisition. See Note 12 for additional information regarding this acquisition.

References to "TEPPCO" mean TEPPCO Partners, L.P. prior to its merger with one of our wholly owned subsidiaries in October 2009.

References to "Offshore Business" refer to the Gulf of Mexico operations we sold to Genesis Energy, L.P. ("Genesis") in July 2015. See Note 5 for information regarding this sale.

References to "EFS Midstream" mean EFS Midstream LLC, which we acquired in July 2015 from affiliates of Pioneer Natural Resources Company ("Pioneer") and Reliance Industries Limited ("Reliance"). See Note 12 for additional information regarding this acquisition.

Note 1. Partnership Operations, Organization and Basis of Presentation

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 liquid ("NGL") 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 import and export terminals (including liquefied petroleum gas or "LPG"); crude oil gathering, transportation, storage and terminals; petrochemical and refined products transportation, storage and terminals, and related services; and a marine transportation business that operates primarily on the U.S. inland and Intracoastal Waterway systems and in the Gulf of Mexico. Our assets currently include approximately 49,000 miles of pipelines; 250 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.

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services. On July 24, 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services segment. Our consolidated financial statements reflect ownership of the Offshore Business through July 24, 2015. See Note 10 for additional information regarding our business segments.

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 the ASA and other related party matters.

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 periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Balance at beginning of period	$ 13.9	$ 7.5	$ 13.2
Charged to costs and expenses	0.8	8.4	2.1
Deductions	(2.6)	(2.0)	(7.8)
Balance at end of period	$ 12.1	$ 13.9	$ 7.5

See "Credit Risk" in Note 18 for additional information.

Cash and Cash Equivalents

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.

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 9 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.

Derivative Instruments

We use derivative instruments such as futures, swaps, options, 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 effective portion of the hedge is reported in other comprehensive income (loss) and is reclassified into 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 hedge relationship 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.

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, 2015, 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 periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Balance at beginning of period	$ 15.6	$ 9.9	$ 13.7
Charged to costs and expenses	6.4	11.9	3.9
Acquisition-related additions and other	1.1	2.5	0.7
Deductions	(10.1)	(8.7)	(8.4)
Balance at end of period	$ 13.0	$ 15.6	$ 9.9

At December 31, 2015 and 2014, $5.8 million and $8.1 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.

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 ethane, propane, normal butane and natural gasoline-based contracts with terms greater than one year and certain options used to hedge natural gas storage inventory and transportation capacities. 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, 2015 and 2014.

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.

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 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 is their fair value estimation process. Based on our most recent goodwill impairment test at December 31, 2015, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

See Note 7 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 impairment charges related to long-lived assets.

Impairment Testing for Unconsolidated Affiliates

We evaluate our equity method investments for impairment when events or changes in circumstances indicate that 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 charge to equity earnings to adjust the carrying value of the investment to its estimated fair value. There were no impairment charges in 2015 and 2014 related to our equity method investments. See Note 6 for information regarding our equity method investments, and Note 14 for information for the related impairment charge recorded during 2013.

Inventories

Inventories primarily consist of NGLs, petrochemicals, refined products, crude oil and natural gas volumes that are valued at the lower of average cost or market. 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 4 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 ratably until the next planned annual outage. 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 5 for additional information regarding our property, plant and equipment and AROs.

Recent Accounting Developments

Revenue Recognition. In May 2014, the Financial Accounting Standards Board ("FASB") and the International Accounting Standards Board finished their joint project in the area of revenue recognition. The resulting accounting standards update eliminates the specific transaction and industry revenue recognition guidance under current U.S. GAAP and replaces it with a principles based approach for determining revenue recognition.

The core principle in the new guidance 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. In order to apply this core principle, companies will apply the following five steps in determining the amount of revenues to recognize: (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's judgment and an analysis of the contract's material terms and conditions.

In light of this recently issued accounting guidance, we started the process of reviewing our revenue contracts in 2015; however, due to the early stage of this process, we are currently not in a position to estimate the impact the new guidance will have on our consolidated financial statements. We expect to adopt the new standard on January 1, 2018 using the modified retrospective approach. This approach allows us to apply the new standard to (i) all new contracts entered into after January 1, 2018 and (ii) all existing contracts as of January 1, 2018 through a cumulative adjustment to equity. Consolidated revenues for periods prior to January 1, 2018 would not be revised.

Leases. A new lease accounting model is being introduced by the FASB. Under the new guidance, substantially all leases (with the exception of leases with a term of 12 months or less) will be recorded on the balance sheet and be classified as either "finance" or "operating" leases on the basis of whether the lessee effectively obtains control of the underlying asset during lease term. A lease would be classified as a finance lease if a lessee meets one of five classification criteria that are generally consistent with current lease accounting guidance. Alternatively, a lease would be classified as an operating lease if it does not meet this criteria. Regardless of classification, the initial measurement of both finance leases and operating leases will result in the balance sheet recognition of a "right-of-use asset" and a corresponding lease liability, which will be recognized at the present value of the lease payments.

The subsequent measurement of each type of lease varies. Leases classified as a finance lease are accounted for using the effective interest method. Under this approach, a lessee would separately amortize the right of use asset (in a manner similar to depreciation) and the discount on the lease liability (as a component of interest expense). Interest expense is separately recorded since a finance lease is viewed as the purchasing and financing of a leased asset. On the cash flow statement, amortization associated with this type of lease would be presented as an adjustment to net income within operating activities and payments on the principal portion of the lease liability would be classified as a financing activity cash outflow.

Leases classified as an operating lease would recognize a single lease expense amount that is recorded on a straight-line basis (or another systematic basis if more appropriate), which combines the unwinding of the discount on the lease liability with the amortization of the right of use asset. For purposes of cash flow statement presentation, operating lease payments would be a component of operating activities.

Due to the recent nature of this guidance, we are currently not in a position to estimate its future impact on our consolidated financial statements. Based on the parameters outlined by the FASB, we expect to adopt the new lease accounting model in 2019.

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 deposit requirements change. At December 31, 2015, our restricted cash amount was $15.9 million. We did not have any restricted cash as of December 31, 2014. See Note 14 for information regarding our derivative instruments and hedging activities.

Note 3. Revenue Recognition

In general, we recognize revenue from our customers when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the buyer's price is fixed or determinable and (iv) collectibility is reasonably assured. Amounts billed in advance of the period in which the service is rendered or product delivered are recorded as deferred revenue. The following information summarizes our revenue recognition policies by business segment. See Note 10 for general information regarding our business segments.

NGL Pipelines & Services

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

Our NGL marketing activities generate revenues from merchant activities such as term and spot sales of NGLs, which we take title to through our natural gas processing activities (i.e., our equity NGL production) and open market and contract purchases. Revenue from these sales contracts is recognized when the NGLs are delivered to customers. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as location, timing or NGL product quality. NGL sales contracts associated with our export facilities may also include take-or-pay provisions.

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

We collect storage revenue under our NGL and related product storage contracts primarily from capacity reservation agreements, where we collect a fee for reserving storage capacity for customers in our underground storage wells. Customers pay reservation fees based on the level of storage capacity reserved rather than the actual volumes stored. Under these agreements, revenue is recognized ratably over the specified reservation period. When a customer exceeds its reserved capacity, we charge that customer excess storage fees, which are recognized in the period of occurrence. 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.

We typically earn revenues from NGL fractionation under fee-based arrangements. These fees are contractually subject to adjustment for changes in certain fractionation expenses (e.g., natural gas fuel costs). Under fee-based arrangements, revenue is recognized in the period services are provided. At our Norco facility in Louisiana, we perform fractionation services for certain customers under percent-of-liquids contracts. Such contracts allow us to retain a contractually determined percentage of the customer's fractionated NGLs as payment for services rendered. Revenue is recognized from such arrangements when we sell and deliver the retained NGLs to customers.

Revenue from NGL import and LPG export terminaling activities is recorded in the period services are provided. Customers are typically billed a fee per unit of volume loaded or unloaded.

Crude Oil Pipelines & Services

Revenues from crude oil transportation contracts and tariffs are generally based upon a fixed fee per barrel (subject to escalation, if applicable) transported multiplied by the volume delivered. Transportation fees charged to shippers are based on either tariffs regulated by governmental agencies, including the FERC, or contractual arrangements. Typically, revenue associated with these arrangements is recognized when volumes are transported and delivered; however, under certain of our crude oil pipeline transportation agreements, customers are required to ship a minimum volume over an agreed-upon period, with make-up rights. Revenue pursuant to such agreements, including that associated with make-up rights, is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired (typically a one year contractual period), or when the pipeline is otherwise released from its transportation service performance obligation.

Revenue from our condensate gathering, processing and stabilization services as well as gathering, treating and compression services is recognized based upon the higher of actual volumes handled or minimum volume commitments. Fees charged for the underlying services are contractually fixed and, if applicable, subject to escalation. With respect to those agreements having minimum volume commitments, the producer pays a deficiency fee when its volumes do not meet contractually defined minimum volume thresholds (there are no make-up rights in connection with these agreements). Under certain of the contracts, if actual volumes handled during a period exceed the respective minimum volume commitment, the excess volume serves to reduce future minimum volume commitments (for periods up to two years in the future), thus reducing any potential deficiency fees that the producer may pay in the future.

Under our crude oil terminaling agreements, we charge customers for crude oil storage based on storage capacity reservation agreements, where we collect a fee for reserving storage capacity for customers at our terminals. Under these agreements, revenue is recognized ratably over the specified reservation period. In addition, we charge our customers throughput (or pumpover) fees based on volumes withdrawn from our terminals. Revenue is also generated from fee-based trade documentation services and is recognized as services are completed.

Our crude oil marketing activities generate revenues from the sale and delivery of crude oil purchased either directly from producers or from others on the open market. These sales contracts generally settle with the physical delivery of crude oil to customers. In general, the sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location, timing or crude oil quality.

Natural Gas Pipelines & Services

Our natural gas pipelines typically generate revenues from transportation agreements under which shippers are billed 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, including the FERC, 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 (whether or not the shipper actually utilizes such capacity). Revenues are recognized when volumes have been delivered to customers or in the period we provide firm capacity reservation services.

Under our natural gas storage revenue contracts, there are typically two components: (i) monthly demand payments, which are associated with a customer's storage capacity reservation and paid regardless of actual usage, and (ii) storage fees per unit of volume stored at our facilities. Revenue from demand payments is recognized during the period the customer reserves capacity. Revenue from storage fees is recognized in the period the services are provided.

Our natural gas marketing activities generate revenue from the sale and delivery to local gas distribution companies and other customers of natural gas purchased from producers, regional natural gas processing plants and the open market. Revenue from these sales contracts is recognized when natural gas is delivered to customers. In general, sales prices referenced in the underlying contracts are market-based and may include pricing differentials for factors such as delivery location.

Petrochemical & Refined Products Services

Our propylene fractionation, butane isomerization and deisobutanizer facilities generate revenue through fee-based arrangements, which typically include a base-processing fee subject to adjustment for changes in power, fuel and labor costs, all of which are the primary costs of propylene fractionation and butane isomerization. Our butane isomerization and deisobutanizer operations also generate revenue from the sale and delivery of by-products. Revenue resulting from such agreements is recognized in the period the services are provided. Revenues from our petrochemical pipeline transportation contracts are primarily based upon a fixed fee per volume transported (typically measured in gallons or pounds and subject to escalation, if applicable) multiplied by the volume delivered.

Our petrochemical marketing activities include the purchase and fractionation of refinery grade propylene obtained in the open market and generate revenues from the sale and delivery of products obtained through propylene fractionation. Revenue from these sales contracts is recognized when such products are delivered to customers. In general, we sell our petrochemical products at market-based prices, which may include pricing differentials for factors such as delivery location. Revenue from the production and sale of octane additives and high purity isobutylene is dependent on the sales price and volume of such commodities sold to customers. Revenue is recognized for sales transactions when the product is delivered.

Pipelines transporting refined products generate revenues through contracts and tariffs as customers are billed a fixed fee per barrel (subject to escalation, if applicable) of liquids transported multiplied by the volume delivered. The fees charged under these arrangements are either contractual or regulated by governmental agencies, including the FERC. Revenue associated with these fee-based contracts and tariffs is recognized when volumes have been delivered. Revenue from our refined products storage facilities is based on capacity reservation agreements where we collect a fee for reserving a defined storage capacity for customers at our facilities. Under these contracts, revenue is recognized ratably over the length of the storage period. Revenue from product terminaling activities is recorded in the period such services are provided. Customers are typically billed a fee per unit of volume loaded.

Revenue is also generated from the provision of inland and offshore marine transportation of refined products, crude oil, condensate, asphalt, heavy fuel oil, LPG and other petroleum products via tow boats and tank barges. Under our marine services transportation contracts, revenue is recognized over the transit time of individual tows as determined on an individual contract basis, which is generally less than ten days in duration. Revenue from these contracts is typically based on set day rates or a set fee per cargo movement. The costs of fuel, substantially all of which is a pass through expense, and other specified operational fees and costs are directly reimbursed by the customer under most of these contracts.

Offshore Pipelines & Services

In July 2015, we sold our Offshore Business to Genesis. See Note 5 for additional information related to the sale of our Offshore Business.

Revenue from offshore pipelines was generally based upon a fixed fee per unit of volume gathered or transported multiplied by the volume delivered. Transportation fees were based either on contractual arrangements or tariffs regulated by the FERC. Revenue associated with these fee-based contracts and tariffs was recognized when volumes were delivered.

Revenues from offshore platform services generally consisted of demand fees and commodity charges. Revenues from offshore platform services were recognized in the period the services were provided. Demand fees represented charges to customers served by offshore platforms regardless of the volume the customer actually delivered to the platform. Revenue from commodity charges was based on a fee per unit of volume delivered to the platform multiplied by the total volume of each product delivered. Contracts for platform services often included both demand fees and commodity charges, but demand fees generally expired after a contractually fixed period of time.

Note 4. Inventories

Our inventory amounts by product type were as follows at the dates indicated:

	December 31,	
	2015	2014
NGLs	$ 639.9	$ 579.1
Petrochemicals and refined products	148.0	295.6
Crude oil	222.1	97.8
Natural gas	28.1	41.7
Total	$ 1,038.1	$ 1,014.2

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 market adjustments for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Cost of sales (1)	$ 19,612.9	$ 40,464.1	$ 40,770.2
Lower of cost or market adjustments within cost of sales	19.8	22.8	18.5

(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 market 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 5. 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, 2015	December 31, 2014
Plants, pipelines and facilities (1)	3-45 (6)	$ 32,525.0	$ 30,834.9
Underground and other storage facilities (2)	5-40 (7)	3,000.5	2,584.2
Platforms and facilities (3)	20-31	--	659.7
Transportation equipment (4)	3-10	159.9	154.2
Marine vessels (5)	15-30	769.8	796.4
Land		262.7	262.6
Construction in progress		3,894.0	2,754.7
Total		40,611.9	38,046.7
Less accumulated depreciation		8,577.2	8,165.1
Property, plant and equipment, net		$ 32,034.7	$ 29,881.6

(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.
(2) Underground and other storage facilities include underground product storage caverns; above ground storage tanks; water wells and related assets.
(3) Platforms and facilities included offshore platforms and related facilities and other associated assets located in the Gulf of Mexico prior to the sale of our Offshore Business.
(4) Transportation equipment includes tractor-trailer tank trucks and other vehicles and similar assets used in our operations.
(5) Marine vessels include tow boats, barges and related equipment used in our marine transportation business.
(6) 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.
(7) 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.

The carrying values of certain fixed asset categories increased primarily as a result of the acquisition of EFS Midstream in July 2015. See Note 12 for information regarding this acquisition.

The following table summarizes our depreciation expense and capitalized interest amounts for the periods indicated:

	For the Year Ended December 31, 2015	2014	2013
Depreciation expense (1)	$ 1,161.6	$ 1,114.1	$ 1,012.4
Capitalized interest (2)	149.1	77.9	133.0

(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.

Sale of Offshore Business

In July 2015, we completed the sale of our Offshore Business, which primarily consisted of our Offshore Pipelines & Services business segment, to Genesis for approximately $1.53 billion in cash. Our Offshore Business served drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Alabama, Louisiana, Mississippi and Texas and included approximately 2,350 miles of offshore natural gas and crude oil pipelines and six offshore hub platforms. Our results of operations reflect ownership of the Offshore Business through July 24, 2015.

At the time of sale, the carrying value of the net assets of the Offshore Business totaled approximately $1.59 billion, which included current assets of $26.9 million, property, plant and equipment of $1.14 billion, investments in unconsolidated affiliates of $482.4 million, intangible assets of $37.1 million and goodwill of $82.0 million. Total liabilities were $116.4 million and noncontrolling interests were $62.2 million at that date. In total, we recorded non-cash losses of $67.1 million for the Offshore Business during 2015, including a $54.8 million asset impairment charge during the second quarter of 2015 and a $12.3 million loss on the sale in July 2015.

We viewed our Offshore Business as an extension of our midstream energy services network. As such, the sale of these assets did not represent a strategic shift in our consolidated operations, and their sale does not have a major effect on our financial results. At December 31, 2014, segment assets for our Offshore Pipelines & Services segment represented 4.3% of consolidated total segment assets. Likewise, gross operating margin from this business segment represented only 3.1% of our consolidated total gross operating margin for the year ended December 31, 2014. The sale of this non-strategic business allowed us to redeploy capital to other business opportunities that we believe will generate a higher rate of return for us in the future (e.g., our acquisition of EFS Midstream). Also, proceeds from the closing of this sale reduced our need to issue additional equity and debt to support our capital spending program.

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, 2015 and 2014 includes $17.6 million and $31.3 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 periods indicated:

	For the Year Ended December 31,		
	2015	**2014**	**2013**
ARO liability beginning balance	$ 98.3	$ 90.2	$ 105.2
Liabilities incurred	2.7	0.1	1.7
Liabilities settled	(6.3)	(2.7)	(14.2)
Revisions in estimated cash flows	49.7	4.6	(8.6)
Accretion expense	5.2	6.1	6.1
AROs related to Offshore Business sold in July 2015	(91.1)	--	--
ARO liability ending balance	$ 58.5	$ 98.3	$ 90.2

Revisions to estimated cash flows for the year ended December 31, 2015 include a $39.5 million adjustment made in the second quarter of 2015 related to the Matagorda Gathering System, which was a component of the Offshore Business. In June 2015, we were notified by the U.S. Army Corps of Engineers (the “CoE”) to fully remove two pipeline segments included in this system that we had originally requested to abandon in-place. As a result, we adjusted the ARO liabilities for those pipeline segments under CoE jurisdiction to account for the estimated cost of removal. All ARO liabilities related to our Offshore Business (including those of the Matagorda Gathering System) were removed from our Consolidated Balance Sheet upon the sale of the Offshore Business on July 24, 2015.

The following table presents our forecast of accretion expense for the periods indicated:

2016	**2017**	**2018**	**2019**	**2020**
$ 3.7	$ 4.0	$ 4.3	$ 4.7	$ 5.0

Note 6. 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, 2015	December 31, 2015	December 31, 2014
NGL Pipelines & Services:			
Venice Energy Service Company, L.L.C. ("VESCO")	13.1%	$ 25.9	$ 27.7
K/D/S Promix, L.L.C. ("Promix")	50%	38.3	38.5
Baton Rouge Fractionators LLC ("BRF")	32.2%	18.5	18.8
Skelly-Belvieu Pipeline Company, L.L.C. ("Skelly-Belvieu")	50%	39.8	40.1
Texas Express Pipeline LLC ("Texas Express")	35%	342.0	349.3
Texas Express Gathering LLC ("TEG")	45%	36.8	37.9
Front Range Pipeline LLC ("Front Range")	33.3%	171.2	170.0
Delaware Basin Gas Processing LLC ("Delaware Processing")	50%	46.2	--
Crude Oil Pipelines & Services:			
Seaway Crude Pipeline Company LLC ("Seaway")	50%	1,396.0	1,431.2
Eagle Ford Pipeline LLC ("Eagle Ford Crude Oil Pipeline")	50%	388.8	336.5
Eagle Ford Terminals Corpus Christi LLC ("Eagle Ford Corpus Christi")	50%	28.6	--
Natural Gas Pipelines & Services:			
White River Hub, LLC ("White River Hub")	50%	22.5	23.2
Petrochemical & Refined Products Services:			
Baton Rouge Propylene Concentrator, LLC ("BRPC")	30%	5.4	6.5
Centennial Pipeline LLC ("Centennial")	50%	65.6	66.1
Other	Various	2.9	2.5
Offshore Pipelines & Services:			
Various, sold to Genesis in July 2015 (see Note 5)	n/a	--	493.7
Total investments in unconsolidated affiliates		$ 2,628.5	$ 3,042.0

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 and related storage caverns 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.

- 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 NGL fractionation and storage complex in Mont Belvieu. This pipeline commenced operations in November 2013. Mixed NGLs from the Rocky Mountains, Permian Basin and Mid-Continent regions are delivered to the Texas Express Pipeline via an interconnect with our Mid-America Pipeline System near Skellytown. The 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.

- TEG owns two NGL gathering systems that deliver volumes to the Texas Express Pipeline. These gathering systems commenced operations in November 2013. The Elk City gathering system 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. An affiliate of Enbridge Energy Partners, L.P. serves as operator of these two NGL gathering systems.

- 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 in Skellytown. The Front Range Pipeline commenced operations in February 2014.

- Delaware Processing was formed with Occidental Petroleum Corporation in April 2015 to plan, design and construct a new 150 million cubic feet per day cryogenic natural gas processing plant to accommodate the growing production of NGL-rich natural gas in the Delaware Basin, in West Texas and southern New Mexico. The facility, located in Reeves County, Texas, will be supported by long-term, firm contracts and is expected to begin operations in mid-2016. We serve as construction manager for the project and will serve as operator once the new facility commences operations.

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 provides north-to-south transportation of crude oil from the Cushing hub to Seaway's Jones Creek terminal near Freeport, Texas and our terminal located near Katy, Texas. In July 2014 we completed a pipeline looping project involving our Longhaul System. This expansion project entailed the construction of an additional pipeline that transports crude oil southbound from the Cushing hub to Seaway's Jones Creek terminal.

  The Freeport System consists of a marine dock, three pipelines and other related facilities that transport crude oil to and from Freeport to the Jones Creek terminal. The Texas City System consists of a ship unloading dock, storage tanks, various pipelines and other related facilities that deliver crude oil from Texas City, Texas to Galena Park, Texas and other nearby locations. The Freeport System and Texas City System make only intrastate movements. Seaway also owns storage tanks at the Jones Creek terminal, which are connected to the Longhaul System, and storage tanks at our Enterprise Crude Houston ("ECHO") terminal.

- Eagle Ford Crude Oil Pipeline owns a crude oil pipeline that transports crude oil and condensate for producers in South Texas that commenced operations in July 2013. The system consists of a crude oil and condensate pipeline system extending from Gardendale, Texas in LaSalle County to Three Rivers, Texas in Live Oak County and continuing on to Corpus Christi, Texas. The system also includes a pipeline segment extending from Three Rivers to an interconnect 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. Plains All American Pipeline, L.P., our joint venture partner in the pipeline, serves as operator of the system.

- Eagle Ford Corpus Christi was formed with Plains Marketing, L.P., a subsidiary of Plains All American Pipeline, L.P., in March 2015 to construct and operate a marine terminal that will handle crude oil delivered by Eagle Ford Crude Oil Pipeline. This terminal is expected to be completed in 2018.

Natural Gas Pipelines & Services

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.

Petrochemical & Refined Products Services

The principal business activity of each significant investee included in our Petrochemical & Refined Products Services segment is described as follows:

- BRPC owns a propylene fractionation facility located in south Louisiana that fractionates refinery grade propylene into chemical grade propylene.

- Centennial owns an interstate refined products pipeline that extends from an origination facility in Beaumont, Texas, to Bourbon, Illinois. Centennial also owns a refined products storage terminal located near Creal Springs, Illinois.

Offshore Pipelines & Services

Our investments in unconsolidated affiliates classified within the Offshore Pipelines & Services segment were sold to Genesis on July 24, 2015 (see Note 5). At June 30, 2015, the carrying value of these investments was $482.4 million.

Equity Earnings

The following table presents our equity in income (loss) of unconsolidated affiliates by business segment for the periods indicated:

	For the Year Ended December 31,		
	2015	**2014**	**2013**
NGL Pipelines & Services	$ 57.5	$ 30.6	$ 15.7
Crude Oil Pipelines & Services	281.4	184.6	140.3
Natural Gas Pipelines & Services	3.8	3.6	3.8
Petrochemical & Refined Products Services (1)	(15.7)	(13.3)	(22.3)
Offshore Pipelines & Services	46.6	54.0	29.8
Total	$ 373.6	$ 259.5	$ 167.3

(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 the market and income approaches, indicate that the fair value of this investment remains substantially 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,	
	2015	**2014**
NGL Pipelines & Services	$ 25.3	$ 26.5
Crude Oil Pipelines & Services	19.3	21.7
Petrochemical & Refined Products Services	2.3	2.4
Offshore Pipelines & Services (1)	--	9.0
Total	$ 46.9	$ 59.6

(1) Our investments in unconsolidated affiliates classified within the Offshore Pipelines & Services segment were sold to Genesis in July 2015.

In total, amortization of excess cost amounts were $4.9 million, $3.3 million and $3.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. We forecast that our amortization of excess cost amount will approximate $2.2 million in each of the next five years.

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,	
	2015	**2014**
Balance Sheet Data:		
Current assets	$ 204.5	$ 289.9
Property, plant and equipment, net	5,671.1	6,766.5
Other assets	58.9	60.4
Total assets	$ 5,934.5	$ 7,116.8
Current liabilities	$ 306.7	$ 305.9
Other liabilities	103.2	309.9
Combined equity	5,524.6	6,501.0
Total liabilities and combined equity	$ 5,934.5	$ 7,116.8

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Income Statement Data:			
Revenues	$ 1,426.6	$ 1,311.3	$ 947.4
Operating income	825.8	600.0	423.9
Net income	814.1	587.9	382.6

Note 7. Intangible Assets and Goodwill

Identifiable Intangible Assets

The following table summarizes our intangible assets by business segment at the dates indicated:

	December 31, 2015			December 31, 2014		
	Gross Value	Accumulated Amortization	Carrying Value	Gross Value	Accumulated Amortization	Carrying Value
NGL Pipelines & Services:						
Customer relationship intangibles	$ 447.4	$ (156.9)	$ 290.5	$ 340.8	$ (183.2)	$ 157.6
Contract-based intangibles	283.0	(193.2)	89.8	277.7	(178.7)	99.0
IDRs (1)	--	--	--	432.6	--	432.6
Segment total	730.4	(350.1)	380.3	1,051.1	(361.9)	689.2
Crude Oil Pipelines & Services:						
Customer relationship intangibles	2,204.4	(39.1)	2,165.3	1,108.0	(7.7)	1,100.3
Contract-based intangibles	281.4	(69.2)	212.2	281.4	(13.5)	267.9
IDRs (1)	--	--	--	855.4	--	855.4
Segment total	2,485.8	(108.3)	2,377.5	2,244.8	(21.2)	2,223.6
Natural Gas Pipelines & Services:						
Customer relationship intangibles	1,350.3	(366.3)	984.0	1,163.6	(308.9)	854.7
Contract-based intangibles	464.7	(361.0)	103.7	466.0	(347.8)	118.2
Segment total	1,815.0	(727.3)	1,087.7	1,629.6	(656.7)	972.9
Petrochemical & Refined Products Services:						
Customer relationship intangibles	185.5	(38.3)	147.2	198.4	(43.3)	155.1
Contract-based intangibles	56.3	(11.8)	44.5	56.3	(7.8)	48.5
IDRs (1)	--	--	--	171.2	--	171.2
Segment total	241.8	(50.1)	191.7	425.9	(51.1)	374.8
Offshore Pipelines & Services: (2)						
Customer relationship intangibles	--	--	--	195.8	(154.9)	40.9
Contract-based intangibles	--	--	--	1.2	(0.5)	0.7
Segment total	--	--	--	197.0	(155.4)	41.6
Total intangible assets	$ 5,273.0	$ (1,235.8)	4,037.2	$ 5,548.4	$ (1,246.3)	$ 4,302.1

(1) We recorded intangible assets having an aggregate carrying value of $1.46 billion in connection with our October 2014 acquisition of the IDRs of Oiltanking. The IDRs represented contractual rights to future cash incentive distributions to be paid by Oiltanking. These rights were granted to Oiltanking GP under the terms of Oiltanking's partnership agreement. Oiltanking GP could separate and sell the IDRs independent of its other residual general partner interest in Oiltanking. In February 2015 (following completion of Step 2 of the Oiltanking acquisition), the Oiltanking IDRs were cancelled and the carrying value of this intangible asset was reclassified to goodwill.

(2) Our intangible assets classified within the Offshore Pipelines & Services segment were sold to Genesis in July 2015 (see Note 5).

The following table presents the amortization expense of our intangible assets by business segment for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
NGL Pipelines & Services	$ 33.6	$ 33.1	$ 36.4
Crude Oil Pipelines & Services	87.1	15.7	1.4
Natural Gas Pipelines & Services	40.0	45.0	50.1
Petrochemical & Refined Products Services	8.9	6.9	6.2
Offshore Pipelines & Services	4.5	9.9	11.5
Total	$ 174.1	$ 110.6	$ 105.6

The following table presents our forecast of amortization expense associated with existing intangible assets for the years indicated:

2016	2017	2018	2019	2020
$ 181.6	$ 177.4	$ 171.6	$ 167.0	$ 166.3

In general, our intangible assets fall within two categories – customer relationship and contract-based intangible assets. The values assigned to such intangible assets are amortized to earnings using either (i) a straight-line approach or (ii) other methods that closely resemble the pattern in which the economic benefits are estimated to be consumed or otherwise used, as appropriate.

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 can be classified as either (i) basin-specific or (ii) general. In certain instances, the acquisition of these intangible assets represents obtaining access to customers in a defined resource basin 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 commercial relationships with existing producers and provides us with opportunities to establish new ones within our existing asset footprint. The duration of such customer relationships is limited by the estimated economic life of the associated resource basin. 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 commercial relationships with existing customers and provides us with opportunities to establish new ones. The duration of these general 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 providing services to customers.

At December 31, 2015, the carrying value of our portfolio of customer relationship intangible assets was $3.59 billion, the principal components of which are as follows:

	Weighted Average Remaining Amortization Period at December 31, 2015	December 31, 2015		
		Gross Value	Accumulated Amortization	Carrying Value
Basin-specific customer relationships:				
EFS Midstream (1)	26.4 years	$ 1,409.8	$ (26.2)	$ 1,383.6
State Line and Fairplay (2)	31.2 years	895.0	(141.7)	753.3
San Juan Gathering (3)	23.8 years	331.3	(196.4)	134.9
Encinal (4)	11.0 years	132.9	(86.9)	46.0
General customer relationships:				
Oiltanking (5)	28.0 years	1,192.5	(11.5)	1,181.0

(1) We acquired these intangible assets in connection with our acquisition of EFS Midstream in July 2015 (see Note 12 for additional information).
(2) These customer relationships are associated with our State Line and Fairplay Gathering Systems, which we acquired in 2010. The State Line system serves producers in the Haynesville and Bossier Shale supply basins and the Cotton Valley and Taylor Sand formations in Louisiana and eastern Texas. The Fairplay system serves producers in the Cotton Valley and Taylor Sand formations within Panola and Rusk counties in East Texas.
(3) These customer relationships are associated with our San Juan Gathering System, which serves producers in the San Juan Basin of northern New Mexico and southern Colorado. We acquired this intangible asset in 2004.
(4) These customer relationships are associated with our Encinal Gathering System, which serves producers in the Olmos and Wilcox formations in South Texas. We acquired this intangible asset in 2006.
(5) We acquired these intangible assets in connection with our acquisition of Oiltanking in October 2014 (see Note 12 for additional information).

EFS Midstream customer relationships
We recorded $1.41 billion of customer relationships in connection with our acquisition of EFS Midstream in July 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 estimated fair value of these customer relationship intangible assets was determined using an income approach, specifically a discounted cash flow analysis. The EFS Midstream customer relationships provide us with long-term access to the natural gas, NGL and condensate resources served by EFS Midstream. Infrastructure like that owned by EFS Midstream requires a significant investment, both in terms of initial construction costs and ongoing maintenance, and is generally supported by long-term contracts with producers (e.g., Pioneer and Reliance) that establish a customer base. The level of expenditures involved in constructing these asset networks can create significant economic barriers to entry that effectively limit competition. The long-term nature of the underlying producer contracts and limited risk of competition ensure a long commercial relationship with existing producers.

The discounted cash flow analysis used to estimate the fair value of the EFS Midstream customer relationships relied on 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 and resource base depletion rates. A discount rate of 15% was applied to the resulting cash flows.

Oiltanking customer relationships
We recorded $1.19 billion of customer relationships in connection with our acquisition of Oiltanking in October 2014. These intangible assets represent the estimated value of the expected patronage of Oiltanking's third party storage and terminal customers.

We valued the customer relationships using an income approach, specifically a discounted cash flow analysis. Our analysis was based on forecasting revenue for the existing terminal customers, including assumed service contract renewals, and then adjusting for expected customer attrition rates. The operating cash flows were then reduced by contributory asset charges. The cash flow projections were based on forecasts used to price the Oiltanking acquisition.

The discounted cash flow analysis used to estimate the fair value of the Oiltanking customer relationships relied on Level 3 fair value inputs, including long-range cash flow forecasts that extend for the estimated economic life of the terminal assets and anticipated service contract renewals. A discount rate of 6.5% was applied to the resulting cash flows.

Contract-based intangible assets
Contract-based intangible assets represent specific commercial rights we acquired in connection with business combinations or asset purchases. At December 31, 2015, the carrying value of our contract-based intangible assets was $450.2 million. Our most significant contract-based intangible assets are the Oiltanking customer contracts and the Jonah natural gas gathering agreements.

Oiltanking customer contracts
We recorded $297.4 million of contract-based intangible assets in connection with our acquisition of Oiltanking in October 2014. These intangible assets represent the estimated value of specific commercial rights we acquired in connection with third party customer storage and terminal contracts at the Houston and Beaumont terminals. We valued the contracts using an income approach. If a contract was in its renewal period and had not been cancelled, we assumed the contract was renewed on equivalent terms to the prior contract. We only valued those contracts that specified a minimum monthly fee, excluding contracts with a de minimis fee.

At December 31, 2015, the carrying value of this group of intangible assets was $225.1 million and the weighted average remaining amortization period for the group was 5.2 years. Amortization expense attributable to these contracts is recorded using a straight-line approach over the terms of the underlying contracts.

Jonah natural gas gathering agreements
These intangible assets represent the value attributed to certain natural gas gathering contracts on the Jonah Gathering System. At December 31, 2015, the carrying value of this group of intangible assets was $76.1 million and the weighted average remaining amortization period for the group was 26.0 years. Amortization expense attributable to these intangible assets is recorded using a units-of-production method based on gathering volumes.

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. The following table presents changes in the carrying amount of goodwill during the periods indicated:

	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Consolidated Total
Balance at December 31, 2012	$ 341.2	$ 311.2	$ 296.3	$ 1,056.0	$ 82.1	$ 2,086.8
Reduction in goodwill related to the sale of assets	--	(6.1)	--	(0.7)	--	(6.8)
Balance at December 31, 2013	341.2	305.1	296.3	1,055.3	82.1	2,080.0
Reclassification of goodwill between segments	520.0	--	--	(520.0)	--	--
Reduction in goodwill related to the sale of assets	--	--	--	--	(0.1)	(0.1)
Addition to goodwill related to the acquisition of Oiltanking	1,349.0	613.6	--	257.7	--	2,220.3
Balance at December 31, 2014	2,210.2	918.7	296.3	793.0	82.0	4,300.2
Reclassification of Oiltanking IDR balances to goodwill in connection with the cancellation of such rights in February 2015 and other adjustments	432.6	850.7	--	170.8	--	1,454.1
Reduction in goodwill related to the sale of assets	--	(2.1)	--	--	(82.0)	(84.1)
Addition to goodwill related to the acquisition of EFS Midstream	8.9	73.7	--	--	--	82.6
Goodwill reclassified to assets held-for-sale	--	--	--	(7.6)	--	(7.6)
Balance at December 31, 2015	$ 2,651.7	$ 1,841.0	$ 296.3	$ 956.2	$ --	$ 5,745.2

We did not record any goodwill impairment charges in 2015, 2014 or 2013. Based on our most recent goodwill impairment test at December 31, 2015, each reporting unit's fair value was substantially in excess of its carrying value (i.e., by at least 10%).

Upon completion of Step 1 of the Oiltanking acquisition in October 2014, we recorded $2.22 billion of goodwill. This amount includes retrospective adjustments to the fair value of the Liquidity Option Agreement made in 2015 (see Note 17). Upon completion of Step 2 of the Oiltanking acquisition in February 2015, the IDRs of Oiltanking were cancelled and the associated $1.45 billion carrying value of this identifiable intangible asset was reclassified to goodwill. In the aggregate, we recorded $3.67 billion of goodwill in connection with the Oiltanking acquisition. Factors contributing to the recognition of goodwill in the Oiltanking acquisition include (i) opportunities for new business and repurposing existing assets for "best use" in order to meet anticipated increased demand for export and logistical services related to North American crude oil, condensate and NGL production, (ii) securing ownership and control of assets that are essential to our other midstream assets and (iii) cost savings from integrating Oiltanking's operations into our midstream asset network. See Note 12 for additional information regarding the Oiltanking acquisition.

In July 2015, we recorded $82.6 million of goodwill in connection with our acquisition of EFS Midstream (see Note 12). In general, we attribute this goodwill to our ability to leverage the acquired business with our existing midstream asset network to create future business opportunities.

In July 2015, we removed $82.0 million of goodwill in connection with sale of the Offshore Business (see Note 5).

Note 8. Debt Obligations

The following table presents our consolidated debt obligations (arranged by company and maturity date) at the dates indicated:

	December 31, 2015	December 31, 2014
EPO senior debt obligations:		
Commercial Paper Notes, variable-rates	$ 1,114.1	$ 906.5
Senior Notes I, 5.00% fixed-rate, due March 2015	--	250.0
Senior Notes X, 3.70% fixed-rate, due June 2015	--	400.0
Senior Notes FF, 1.25% fixed-rate, due August 2015	--	650.0
Senior Notes AA, 3.20% fixed-rate, due February 2016	750.0	750.0
364-Day Credit Agreement, variable-rate, due September 2016	--	--
Senior Notes L, 6.30% fixed-rate, due September 2017	800.0	800.0
Senior Notes V, 6.65% fixed-rate, due April 2018	349.7	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
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
Multi-Year Revolving Credit Facility, variable-rate, due September 2020	--	--
Senior Notes CC, 4.05% fixed-rate, due February 2022	650.0	650.0
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	--
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	875.0	--
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	0.3
TEPPCO Senior Notes, 7.55% fixed-rate, due April 2038	0.4	0.4
Total principal amount of senior debt obligations	21,264.1	19,856.5
EPO Junior Subordinated Notes A, fixed/variable-rate, due August 2066 (1)	521.1	550.0
EPO Junior Subordinated Notes C, fixed/variable-rate, due June 2067 (2)	256.4	285.8
EPO Junior Subordinated Notes B, fixed/variable-rate, due January 2068 (3)	682.7	682.7
TEPPCO Junior Subordinated Notes, fixed/variable-rate, due June 2067	14.2	14.2
Total principal amount of senior and junior debt obligations	22,738.5	21,389.2
Other, non-principal amounts	(47.9)	(25.4)
Less current maturities of debt	(1,863.9)	(2,206.4)
Total long-term debt	$ 20,826.7	$ 19,157.4

(1) Fixed rate of 8.375% through August 1, 2016 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 3.708%.

(2) Fixed rate of 7.000% through September 1, 2017 (i.e., first call date without a make-whole redemption premium); thereafter, variable rate based on 3-month LIBOR plus 2.778%.

(3) Fixed rate of 7.034% through January 15, 2018 (i.e., first call date without a make-whole redemption premium); thereafter, the rate will be the greater of 7.034% or a variable rate based on 3-month LIBOR plus 2.680%.

The following table presents contractually scheduled maturities of our consolidated debt obligations outstanding at December 31, 2015 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt					
	Total	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Commercial Paper Notes	$ 1,114.1	$ 1,114.1	$ --	$ --	$ --	$ --	$ --
Senior Notes	20,150.0	750.0	800.0	1,100.0	1,500.0	1,500.0	14,500.0
Junior Subordinated Notes	1,474.4	--	--	--	--	--	1,474.4
Total	$ 22,738.5	$ 1,864.1	$ 800.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 15,974.4

In February 2016, we repaid EPO's $750 million Senior Notes AA using available cash, borrowings under our Multi-Year Revolving Credit Facility and proceeds from the issuance of short-term notes under our commercial paper program.

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. EPO maintains a commercial paper program under which it may issue (and have outstanding at any time) up to $2.5 billion in the aggregate of short-term notes. 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 2015, EPO amended its 364-Day Credit Agreement to extend its maturity date to September 2016. There are currently no principal amounts outstanding under this revolving credit agreement. Under the terms of the 364-Day Credit Agreement, EPO may borrow up to $1.5 billion (which may be increased by up to $200 million to $1.7 billion at EPO's election, provided certain conditions are met) at a variable interest rate for a term of 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 2017.

The 364-Day 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 the 364-Day Credit Agreement. The 364-Day Credit Agreement also restricts EPO's ability to pay cash distributions to its parent, Enterprise Products Partners L.P., if a default or an event of default (as defined in the 364-Day Credit Agreement) has occurred and is continuing at the time such distribution is scheduled to be paid or would result therefrom.

Multi-Year Revolving Credit Facility. In September 2015, EPO amended its Multi-Year Revolving Credit Facility to increase its borrowing capacity from $3.5 billion to $4.0 billion and extend its maturity date from June 2018 to September 2020. The amended credit agreement also provides that EPO may increase its borrowing capacity to $4.5 billion by allowing existing lenders under the facility to increase their respective commitments or by adding one or more new lenders to the facility. Borrowings under this revolving credit facility may be used for working capital, capital expenditures, acquisitions and general company purposes.

As defined by the credit agreement, variable interest rates charged under this revolving credit facility bear interest at LIBOR plus an applicable margin. In addition, EPO is required to pay a quarterly facility fee on each lender's commitment irrespective of commitment usage. This revolving credit facility allows us to request up to two one-year extensions of the maturity date, subject to lender approval.

The Multi-Year Revolving Credit Facility contains certain financial and other customary affirmative and negative covenants. The credit agreement also restricts EPO's ability to pay cash distributions to Enterprise Products Partners L.P. if a default or 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. EPO's borrowings under this revolving credit facility are unsecured general obligations that are guaranteed by Enterprise Products Partners L.P. and are non-recourse to Enterprise GP.

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 $2.5 billion, $4.75 billion and $2.25 billion of senior notes during the years ended December 31, 2015, 2014 and 2013, respectively.

In May 2015, EPO issued $750 million in principal amount of 1.65% senior notes due May 2018 ("Senior Notes OO"), $875 million in principal amount of 3.70% senior notes due February 2026 ("Senior Notes PP") and $875 million in principal amount of 4.90% senior notes due May 2046 ("Senior Notes QQ"). Senior Notes OO, PP and QQ were issued at 99.881%, 99.635% and 99.635% of their principal amounts, respectively.

Net proceeds from the issuance of these senior notes were used as follows: (i) the repayment of amounts outstanding under EPO's commercial paper program, which included amounts we used to repay $250 million in principal amount of Senior Notes I that matured in March 2015, (ii) the repayment of amounts outstanding at the maturity of our $400 million in principal amount of Senior Notes X that matured in June 2015 and (iii) for general company purposes.

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 absent payment of a make-whole premium (while such notes bear interest at a fixed annual rate).

In connection with the issuance of each series of junior notes, 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.

During 2015, EPO repurchased and retired $28.9 million in principal amount of its Junior Subordinated Notes A and $29.4 million in principal amount of its Junior Subordinated Notes C with cash from operations. A $1.6 million gain on the extinguishment of these debt obligations is included in "Other, net" on our Statements of Consolidated Operations.

The following table summarizes the interest rate terms of our junior subordinated notes:

Series	Fixed Annual Interest Rate	Variable Annual Interest Rate Thereafter
Junior Subordinated Notes A	8.375% through August 2016 (1)	3-month LIBOR rate + 3.708% (4)
Junior Subordinated Notes B	7.034% through January 2018 (2)	Greater of: (i) 3-month LIBOR rate + 2.680% or (ii) 7.034% (5)
Junior Subordinated Notes C	7.000% through September 2017 (3)	3-month LIBOR rate + 2.778% (6)

(1) Interest is payable semi-annually in arrears in February and August of each year, which commenced in February 2007.
(2) Interest is payable semi-annually in arrears in January and July of each year, which commenced in January 2008.
(3) Interest is payable semi-annually in arrears in June and December of each year, which commenced in December 2009.
(4) Interest is payable quarterly in arrears in February, May, August and November of each year commencing in November 2016.
(5) Interest is payable quarterly in arrears in January, April, July and October of each year commencing in April 2018.
(6) Interest is payable quarterly in arrears in March, June, September and December of each year commencing in June 2017.

Letters of Credit

At December 31, 2015, EPO had $2.5 million of letters of credit outstanding related to operations at our facilities and motor fuel tax obligations.

Lender Financial Covenants

We were in compliance with the financial covenants of our consolidated debt agreements at December 31, 2015.

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, 2015:

	Range of Interest Rates Paid	Weighted-Average Interest Rate Paid
Commercial Paper Notes	0.35% to 0.92%	0.58%
Multi-Year Revolving Credit Facility	1.15% to 3.25%	1.30%

Debt Issuance Costs

At December 31, 2015, we had $159.8 million of unamortized debt issuance costs recorded as assets, of which $149.8 million was attributable to senior and junior subordinated note obligations (collectively referred to as “bond issuance costs”) and $10.0 million attributable to revolving credit arrangements. In accordance with recently issued accounting guidance effective January 1, 2016, the unamortized bond issuance costs will be presented as a reduction in the carrying amount of debt (as opposed to an asset), consistent with the presentation of debt discounts.

Note 9. Equity and Distributions

Partners Equity

Partners' equity reflects the various classes of limited partner interests (i.e., common units, including restricted common units, and Class B units) that we have outstanding. The following table summarizes changes in the number of our outstanding units since December 31, 2012:

	Common Units (Unrestricted)	Restricted Common Units	Total Common Units
Number of units outstanding at December 31, 2012	1,789,839,702	7,786,972	1,797,626,674
Common units issued in connection with underwritten offering	36,800,000	--	36,800,000
Common units issued in connection with ATM program	15,249,378	--	15,249,378
Common units issued in connection with DRIP and EUPP	10,308,254	--	10,308,254
Common units issued in connection with the vesting and exercise of unit options	401,764	--	401,764
Common units issued in connection with the vesting of restricted common unit awards	3,770,696	(3,770,696)	--
Conversion and reclassification of Class B units to common units	9,040,862	--	9,040,862
Restricted common unit awards issued	--	3,549,052	3,549,052
Forfeiture of restricted common unit awards	--	(344,114)	(344,114)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(1,261,854)	--	(1,261,854)
Number of units outstanding at December 31, 2013	1,864,148,802	7,221,214	1,871,370,016
Common units issued in connection with ATM program	1,590,334	--	1,590,334
Common units issued in connection with DRIP and EUPP	9,754,227	--	9,754,227
Common units issued in connection with Step 1 of Oiltanking acquisition	54,807,352	--	54,807,352
Common units issued in connection with the vesting and exercise of unit options	1,014,108	--	1,014,108
Common units issued in connection with the vesting of phantom unit awards	23,311	--	23,311
Common units issued in connection with the vesting of restricted common unit awards	2,634,074	(2,634,074)	--
Forfeiture of restricted common unit awards	--	(357,350)	(357,350)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(894,383)	--	(894,383)
Other	17,202	--	17,202
Number of units outstanding at December 31, 2014	1,933,095,027	4,229,790	1,937,324,817
Common units issued in connection with ATM program	25,520,424	--	25,520,424
Common units issued in connection with DRIP and EUPP	12,793,913	--	12,793,913
Common units issued in connection with Step 2 of Oiltanking acquisition	36,827,517	--	36,827,517
Common units issued in connection with the vesting and exercise of unit options	396,158	--	396,158
Common units issued in connection with the vesting of phantom unit awards	618,395	--	618,395
Common units issued in connection with the vesting of restricted common unit awards	2,009,970	(2,009,970)	--
Forfeiture of restricted common unit awards	--	(259,300)	(259,300)
Acquisition and cancellation of treasury units in connection with the vesting of equity-based awards	(683,954)	--	(683,954)
Other	15,054	--	15,054
Number of units outstanding at December 31, 2015	2,010,592,504	1,960,520	2,012,553,024

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.

2013 Shelf. In June 2013, we filed with the U.S. Securities and Exchange Commission ("SEC") a new universal shelf registration statement (the "2013 Shelf") that replaced our prior universal shelf registration statement filed with the SEC in July 2010 (the "2010 Shelf"). The 2013 Shelf allows (and the prior 2010 Shelf allowed) Enterprise Products Partners L.P. and EPO (each on a standalone basis) to issue an unlimited amount of equity and debt securities, respectively. We used the 2013 Shelf and 2010 Shelf to facilitate the following securities offerings:

- We used the 2010 Shelf to issue 18,400,000 common units to the public (including an over-allotment amount of 2,400,000 common units) at an offering price of $27.28 per unit in February 2013, which generated net cash proceeds of $486.6 million. In addition, EPO issued $2.25 billion of unsecured senior notes during 2013 using the 2010 Shelf.

- We used the 2013 Shelf to issue 18,400,000 common units to the public (including an over-allotment amount of 2,400,000 common units) at an offering price of $31.03 per unit in November 2013, which generated net cash proceeds of $553.0 million.

- We used the 2013 Shelf to issue $4.75 billion of unsecured senior notes during 2014.

- We used the 2013 Shelf to issue $2.5 billion of unsecured senior notes during 2015 (see Note 8).

At-the-Market ("ATM") Program. On July 1, 2015, we filed a registration statement with the SEC covering the issuance of up to $1.92 billion of our common units in amounts, at prices and on terms to be determined by market conditions and other factors at the time of such offerings. Pursuant to the ATM 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. The new registration statement was declared effective on August 3, 2015 and replaced our prior registration statement with respect to the ATM program, which was filed with the SEC in October 2013 and covered the issuance of up to $1.25 billion of our common units. Immediately prior to the effectiveness of the new registration statement, we had the capacity to issue additional common units under the ATM program up to an aggregate sales price of $424.6 million (after giving effect to sales of common units previously made under the ATM program).

During 2015, we issued 25,520,424 common units under our ATM program for aggregate gross cash proceeds of $825.4 million, resulting in total net cash proceeds of $817.4 million. This includes 3,225,057 common units sold in March 2015 to a privately held affiliate of EPCO, which generated gross proceeds of $100 million. During 2014, we issued 1,590,334 common units under our ATM program for aggregate gross cash proceeds of $58.3 million, resulting in total net cash proceeds of $57.7 million. During 2013, we issued 15,249,378 common units under our ATM for aggregate gross cash proceeds of $460.4 million, resulting in total net cash proceeds of $456.3 million. Following the effectiveness of the new registration statement and after taking into account the aggregate sales price of common units sold under our ATM program through December 31, 2015, we have the capacity to issue additional common units under our ATM program up to an aggregate sales price of $1.86 billion.

DRIP and EUPP. We also have registration statements on file with the SEC collectively authorizing the issuance of up to 140,000,000 of our common units in connection with a 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 new common units. Activity under our DRIP for the last three years was as follows: 12,413,351 common units issued during 2015, which generated net cash proceeds of $359.8 million; 9,480,407 common units issued during 2014, which generated net cash proceeds of $321.3 million; and 10,024,828 common units issued during 2013, which generated net cash proceeds of $287.6 million. Privately held affiliates of EPCO reinvested $100 million through the DRIP in each of 2015 and 2014 (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, 2015, we have the capacity to issue an additional 15,067,998 common units under this plan.

In addition to the DRIP, we have registration statements on file with the SEC authorizing the issuance of up to 8,000,000 of our common units in connection with an employee unit purchase plan ("EUPP"). Activity under our EUPP for the last three years was as follows: 380,562 common units issued during 2015, which generated net cash proceeds of $11.4 million; 273,820 common units issued during 2014, which generated net cash proceeds of $9.8 million; and 283,426 common units issued during 2013, which generated net cash proceeds of $8.5 million. After taking into account the number of common units issued under the EUPP through December 31, 2015, we may issue an additional 6,772,506 common units under this plan.

The net cash proceeds we received from the issuance of common units during the year ended December 31, 2015 were used to temporarily reduce amounts outstanding under EPO's commercial paper program and revolving credit facilities and for general company purposes.

Registration Rights Agreement. In order to fund the equity consideration paid in Step 1 of the Oiltanking acquisition (see Note 12), 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, at any time after the earlier of (i) 90 days after October 1, 2014 and (ii) the execution of definitive agreements to acquire (through merger or otherwise) all or substantially all of the Oiltanking common units not owned by Enterprise or its affiliates, OTA may request that we prepare and file a registration statement to permit and otherwise facilitate the public resale of all or a portion of the 54,807,352 Enterprise common units that OTA owns. Our obligation to OTA to effect such transactions is limited to five registration statements and underwritten offerings.

Completion of Oiltanking Acquisition. In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including our ownership interests) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,517 of our common units were issued to Oiltanking's former public unitholders.

Step 2 of the acquisition was accounted for in accordance with ASC Topic 810, *Consolidations – Overall – Changes in Parent's Ownership Interest in a Subsidiary*. Since we had a controlling financial interest in Oiltanking before and after completion of Step 2, the increase in our ownership interest in Oiltanking was accounted for as an equity transaction with no gain or loss recognized. Step 2 represented our acquisition of the noncontrolling interests in Oiltanking; therefore, approximately $1.4 billion of noncontrolling interests attributable to Oiltanking were reclassified to limited partners' equity to reflect the February 2015 issuance of 36,827,517 new common units.

Class B Units. In connection with the TEPPCO merger in October 2009, a privately held affiliate of EPCO exchanged a portion of its TEPPCO units (based on a 1.24 exchange ratio) for 9,040,862 of our Class B units in lieu of receiving common units. The Class B units automatically converted into the same number of common units on the date immediately following the payment date for the sixteenth regular quarterly distribution following the closing date of the TEPPCO merger. The Class B units were entitled to vote together with our common units as a single class on partnership matters and generally had the same rights and privileges as our common units, except that the Class B units were not entitled to receive regular quarterly cash distributions until they automatically converted into an equal number of common units on August 8, 2013.

Treasury Units. In December 1998, we announced a common unit repurchase program whereby we, together with certain affiliates, intended to repurchase up to 4,000,000 of our common units. A total of 2,763,200 common units were repurchased under this program; however, no repurchases have been made since 2002. As of December 31, 2015, we and our affiliates could repurchase up to 1,236,800 additional common units under this program.

A total of 2,009,970 restricted common unit awards granted to employees of EPCO vested and converted to common units during the year ended December 31, 2015. Of this amount, 683,954 were sold back to us by employees to cover related withholding tax requirements. The total cost of these treasury unit purchases was approximately $33.6 million. We cancelled such treasury units immediately upon acquisition. See Note 13 for additional information regarding our equity-based awards.

Two-for-One Split of Limited Partner Units. In July 2014, we announced that our general partner approved a two-for-one split of our common units. The common unit split was completed on August 21, 2014 by distributing one additional common unit for each common unit outstanding (to holders of record as of the close of business on August 14, 2014). All per unit amounts and number of Enterprise units outstanding in this annual report are presented on a post-split basis.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive income (loss) primarily reflects the effective portion of the gain or loss on derivative instruments designated and qualified as cash flow hedges. 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.

The following tables present the components of accumulated other comprehensive income (loss) as reported on our Consolidated Balance Sheets at the dates indicated:

	Gains (Losses) on Cash Flow Hedges			
	Commodity Derivative Instruments	Interest Rate Derivative Instruments	Other	Total
Balance, December 31, 2013	$ (14.7)	$ (347.2)	$ 2.9	$ (359.0)
Other comprehensive income before reclassifications	161.3	--	0.4	161.7
Amounts reclassified from accumulated other comprehensive (income) loss	(76.7)	32.4	--	(44.3)
Total other comprehensive income	84.6	32.4	0.4	117.4
Balance, December 31, 2014	69.9	(314.8)	3.3	(241.6)
Other comprehensive income before reclassifications	214.9	--	0.4	215.3
Amounts reclassified from accumulated other comprehensive (income) loss	(228.2)	35.3	--	(192.9)
Total other comprehensive income (loss)	(13.3)	35.3	0.4	22.4
Balance, December 31, 2015	$ 56.6	$ (279.5)	$ 3.7	$ (219.2)

The following table presents reclassifications out of accumulated other comprehensive income (loss) into net income during the periods indicated:

		For the Year Ended December 31,	
	Location	2015	2014
Losses (gains) on cash flow hedges:			
Interest rate derivatives	Interest expense	$ 35.3	$ 32.4
Commodity derivatives	Revenue	(231.7)	(75.0)
Commodity derivatives	Operating costs and expenses	3.5	(1.7)
Total		$ (192.9)	$ (44.3)

Noncontrolling Interests

Noncontrolling interests represent third party equity ownership interests in our consolidated subsidiaries.

We reclassified approximately $1.4 billion of noncontrolling interests to limited partners' equity in connection with completing Step 2 of the Oiltanking acquisition in February 2015. Cash distributions paid in the first quarter of 2015 to the limited partners of Oiltanking other than EPO and its subsidiaries are presented as amounts paid to noncontrolling interests.

In February 2015, we formed a joint venture involving our Panola NGL Pipeline with affiliates of Anadarko Petroleum Corporation ("Anadarko"), DCP Midstream Partners, LP ("DCP") and MarkWest Energy Partners, L.P. ("MarkWest"). We continue to serve as operator of the Panola Pipeline and own 55% of the member interests in the joint venture. Affiliates of Anadarko, DCP and MarkWest own the remaining 45% member interests, with each holding a 15% interest. The Panola Pipeline transports mixed NGLs from points near Carthage, Texas to Mont Belvieu, Texas and supports the Haynesville and Cotton Valley oil and gas production areas.

The following table presents additional information regarding noncontrolling interests as presented on our Consolidated Balance Sheets at the dates indicated:

	December 31,	
	2015	2014
Limited partners of Oiltanking other than EPO	$ --	$ 1,408.9
Joint venture partners	206.0	220.1
Total	$ 206.0	$ 1,629.0

The following table presents the components of net income attributable to noncontrolling interests as presented on our Statements of Consolidated Operations for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Limited partners of Oiltanking other than EPO	$ 7.8	$ 14.2	$ --
Joint venture partners	29.4	31.9	10.2
Total	$ 37.2	$ 46.1	$ 10.2

The following table presents cash distributions paid to and cash contributions received from noncontrolling interests as presented on our Statements of Consolidated Cash Flows and Statements of Consolidated Equity for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Cash distributions paid to noncontrolling interests:			
Limited partners of Oiltanking other than EPO	$ 8.1	$ 7.7	$ --
Joint venture partners	39.9	40.9	8.9
Total	$ 48.0	$ 48.6	$ 8.9
Cash contributions from noncontrolling interests:			
Joint venture partners	$ 54.0	$ 4.0	$ 115.4

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
2014:			
1st Quarter	$ 0.3550	4/30/2014	5/7/2014
2nd Quarter	$ 0.3600	7/31/2014	8/7/2014
3rd Quarter	$ 0.3650	10/31/2014	11/7/2014
4th Quarter	$ 0.3700	1/30/2015	2/6/2015
2015:			
1st Quarter	$ 0.3750	4/30/2015	5/7/2015
2nd Quarter	$ 0.3800	7/31/2015	8/7/2015
3rd Quarter	$ 0.3850	10/30/2015	11/6/2015
4th Quarter	$ 0.3900	1/29/2016	2/5/2016

In November 2010, we completed our merger with Enterprise GP Holdings L.P. (the "Holdings Merger"). In connection with the Holdings Merger, a privately held affiliate of EPCO agreed to temporarily waive the regular cash distributions it would otherwise receive from us with respect to a certain number of our common units it owns (the "Designated Units"). Distributions paid to partners during calendar years 2013, 2014 and 2015 excluded 47,400,000, 45,120,000 and 35,380,000 Designated Units, respectively. The temporary distribution waiver expired in November 2015; therefore, distributions to be paid, if any, during calendar year 2016 will include all common units owned by the privately held affiliates of EPCO.

Note 10. Business Segments

Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & 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 President and the Chief Executive Officer 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 current assets and operations of each business segment (mileage and other statistics are unaudited):

- Our NGL Pipelines & Services business segment includes our natural gas processing plants and related NGL marketing activities; approximately 19,500 miles of NGL pipelines; NGL and related product storage facilities; and 15 NGL fractionators. This segment also includes our NGL export docks and related operations.

- Our Crude Oil Pipelines & Services business segment includes approximately 5,400 miles of crude oil pipelines, crude oil storage terminals located in Oklahoma and Texas, and our crude oil marketing activities. This segment also includes a fleet of 478 tractor-trailer tank trucks, the majority of which we lease and operate, used to transport crude oil for us and third parties.

- Our Natural Gas Pipelines & Services business segment includes approximately 19,100 miles of natural gas pipeline systems that provide for the gathering and transportation of natural gas in Colorado, Louisiana, New Mexico, Texas and Wyoming. We lease underground salt dome natural gas storage facilities located in Texas and Louisiana and own an underground salt dome storage cavern in Texas, all of which are important to our natural gas pipeline operations. This segment also includes our related natural gas marketing activities.

- Our Petrochemical & Refined Products Services business segment includes (i) propylene fractionation and related operations, including 674 miles of pipelines; (ii) a butane isomerization complex, associated deisobutanizer units and related pipeline assets; (iii) octane enhancement and high purity isobutylene production facilities; (iv) refined products pipelines aggregating approximately 4,200 miles, terminals and related marketing activities; and (v) marine transportation.

- Our Offshore Pipelines & Services business segment, which served some of the most active drilling and development regions, including deepwater production fields, in the northern Gulf of Mexico offshore Texas, Louisiana, Mississippi and Alabama was sold, effective July 24, 2015. Our results of operations reflect ownership of the Offshore Business through July 24, 2015 (see Note 5).

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.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our executive management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP financial measure most directly comparable to total segment gross operating margin is operating income.

In total, gross operating margin represents operating income exclusive of (1) depreciation, amortization and accretion expenses, (2) impairment charges, (3) gains and losses attributable to asset sales and insurance recoveries and (4) general and administrative costs. Gross operating margin includes equity in income of unconsolidated affiliates and non-refundable deferred transportation revenues relating to the make-up rights of committed shippers associated with certain pipelines. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation. 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.

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 Texas Express Pipeline to transport mixed NGLs to our Mont Belvieu complex for fractionation and storage. 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.

Segment assets consist of property, plant and equipment, investments in unconsolidated affiliates, intangible assets and goodwill. The carrying values of such amounts are assigned to each segment based on each asset's or investment's principal operations and contribution to the gross operating margin of that particular segment. Since construction-in-progress amounts (a component of property, plant and equipment) generally do not contribute to segment gross operating margin, such amounts are excluded from segment asset totals until the underlying assets are placed in service. Intangible assets and goodwill are assigned to each segment based on the classification of the assets to which they relate. Substantially all of our plants, pipelines and other fixed assets are located in the U.S. The remainder of our consolidated total assets, which consist primarily of working capital assets, are excluded from segment assets since these amounts are not attributable to one specific segment (e.g. cash).

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 typically entail the shipper paying a transportation fee based on a minimum volume commitment, with a provision that allows the shipper to make-up any volume shortfalls over the agreed-upon period (referred to as shipper "make-up rights"). Revenue pursuant to such agreements, including that associated with make-up rights, is initially deferred and subsequently recognized at the earlier of when the deficiency volume is shipped, when the shipper's ability to meet the minimum volume commitment has expired (typically a one year contractual period), or when the pipeline is otherwise released from its transportation service performance obligation.

However, management includes deferred transportation revenues relating to the "make-up rights" of committed shippers when reviewing the financial results of certain major new pipeline projects. From an internal (and segment) reporting standpoint, management considers the transportation fees paid by committed shippers on major new 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. Since management includes these deferred revenues in non-GAAP gross operating margin, these amounts are deducted in determining GAAP-based operating income. Our consolidated revenues do not reflect any deferred revenues until the conditions for recognizing such revenues are met in accordance with GAAP.

Several of our major new liquids pipeline projects experienced periods where shippers were unable to meet their contractual minimum volume commitments. In general, we expect that these types of shortfalls will continue in 2016 due to the current business environment, with the recognition of revenue associated with past deferrals associated with make-up rights partially or entirely offsetting any new make-up right deferrals.

The following table presents our measurement of non-GAAP total segment gross operating margin for the periods indicated:

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Revenues	$ 27,027.9	$ 47,951.2	$ 47,727.0
Subtract operating costs and expenses	(23,668.7)	(44,220.5)	(44,238.7)
Add equity in income of unconsolidated affiliates	373.6	259.5	167.3
Add depreciation, amortization and accretion expense amounts not reflected in gross operating margin	1,428.2	1,282.7	1,148.9
Add impairment charges not reflected in gross operating margin	162.6	34.0	92.6
Add net losses or subtract net gains attributable to asset sales and insurance recoveries not reflected in gross operating margin (see Note 19)	15.6	(102.1)	(83.4)
Add non-refundable deferred revenues attributable to shipper make-up rights on major new pipeline projects reflected in gross operating margin	53.6	84.6	4.4
Subtract subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	(60.7)	(2.9)	--
Total segment gross operating margin	$ 5,332.1	$ 5,286.5	$ 4,818.1

The following table presents a reconciliation of total segment gross operating margin to operating income and further to income before income taxes for the periods indicated:

	For the Year Ended December 31,		
	2015	**2014**	**2013**
Total segment gross operating margin	$ 5,332.1	$ 5,286.5	$ 4,818.1
Adjustments to reconcile total segment gross operating margin to operating income:			
Subtract depreciation, amortization and accretion expense amounts not reflected in gross operating margin	(1,428.2)	(1,282.7)	(1,148.9)
Subtract impairment charges not reflected in gross operating margin	(162.6)	(34.0)	(92.6)
Add net gains or subtract net losses attributable to asset sales and insurance recoveries not reflected in gross operating margin	(15.6)	102.1	83.4
Subtract non-refundable deferred revenues attributable to shipper make-up rights on major new pipeline projects reflected in gross operating margin	(53.6)	(84.6)	(4.4)
Add subsequent recognition of deferred revenues attributable to make-up rights not reflected in gross operating margin	60.7	2.9	--
Subtract general and administrative costs not reflected in gross operating margin	(192.6)	(214.5)	(188.3)
Operating income	3,540.2	3,775.7	3,467.3
Other expense, net	(984.3)	(919.1)	(802.7)
Income before income taxes	$ 2,555.9	$ 2,856.6	$ 2,664.6

Information by business segment, together with reconciliations to our consolidated financial statement totals, is presented in the following table:

	Reportable Business Segments						
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:							
Year ended December 31, 2015	$ 9,779.0	$ 10,258.3	$ 2,729.5	$ 4,111.9	$ 76.9	$ --	$ 26,955.6
Year ended December 31, 2014	17,078.4	20,151.9	4,182.6	6,316.5	150.3	--	47,879.7
Year ended December 31, 2013	17,119.1	20,609.1	3,522.7	6,258.5	151.7	--	47,661.1
Revenues from related parties:							
Year ended December 31, 2015	9.0	47.6	13.8	--	1.9	--	72.3
Year ended December 31, 2014	11.4	32.4	21.2	--	6.5	--	71.5
Year ended December 31, 2013	1.1	41.3	15.8	--	7.7	--	65.9
Intersegment and intrasegment revenues:							
Year ended December 31, 2015	10,217.9	5,162.0	662.1	1,126.0	0.6	(17,168.6)	--
Year ended December 31, 2014	13,716.5	12,678.7	1,106.7	1,779.6	6.5	(29,288.0)	--
Year ended December 31, 2013	11,096.6	10,222.3	959.7	1,764.0	9.6	(24,052.2)	--
Total revenues:							
Year ended December 31, 2015	20,005.9	15,467.9	3,405.4	5,237.9	79.4	(17,168.6)	27,027.9
Year ended December 31, 2014	30,806.3	32,863.0	5,310.5	8,096.1	163.3	(29,288.0)	47,951.2
Year ended December 31, 2013	28,216.8	30,872.7	4,498.2	8,022.5	169.0	(24,052.2)	47,727.0
Equity in income (loss) of unconsolidated affiliates:							
Year ended December 31, 2015	57.5	281.4	3.8	(15.7)	46.6	--	373.6
Year ended December 31, 2014	30.6	184.6	3.6	(13.3)	54.0	--	259.5
Year ended December 31, 2013	15.7	140.3	3.8	(22.3)	29.8	--	167.3
Gross operating margin:							
Year ended December 31, 2015	2,771.6	961.9	782.6	718.5	97.5	--	5,332.1
Year ended December 31, 2014	2,877.7	762.5	803.3	681.0	162.0	--	5,286.5
Year ended December 31, 2013	2,514.4	742.7	789.0	625.9	146.1	--	4,818.1
Property, plant and equipment, net: (see Note 5)							
At December 31, 2015	12,909.7	3,550.3	8,620.0	3,060.7	--	3,894.0	32,034.7
At December 31, 2014	11,766.9	2,332.2	8,835.5	3,047.2	1,145.1	2,754.7	29,881.6
At December 31, 2013	9,957.8	1,479.9	8,917.3	2,712.4	1,223.7	2,655.5	26,946.6
Investments in unconsolidated affiliates: (see Note 6)							
At December 31, 2015	718.7	1,813.4	22.5	73.9	--	--	2,628.5
At December 31, 2014	682.3	1,767.7	23.2	75.1	493.7	--	3,042.0
At December 31, 2013	645.5	1,165.2	24.2	70.4	531.8	--	2,437.1
Intangible assets, net: (see Note 7)							
At December 31, 2015	380.3	2,377.5	1,087.7	191.7	--	--	4,037.2
At December 31, 2014	689.2	2,223.6	972.9	374.8	41.6	--	4,302.1
At December 31, 2013	285.2	4.5	1,017.8	100.0	54.7	--	1,462.2
Goodwill: (see Note 7)							
At December 31, 2015	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
At December 31, 2014	2,210.2	918.7	296.3	793.0	82.0	--	4,300.2
At December 31, 2013	341.2	305.1	296.3	1,055.3	82.1	--	2,080.0
Segment assets:							
At December 31, 2015	16,660.4	9,582.2	10,026.5	4,282.5	--	3,894.0	44,445.6
At December 31, 2014	15,348.6	7,242.2	10,127.9	4,290.1	1,762.4	2,754.7	41,525.9
At December 31, 2013	11,229.7	2,954.7	10,255.6	3,938.1	1,892.3	2,655.5	32,925.9

The following table presents additional information regarding our consolidated revenues and costs and expenses for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
NGL Pipelines & Services:			
Sales of NGLs and related products	$ 8,044.8	$ 15,460.1	$ 15,916.0
Midstream services	1,743.2	1,629.7	1,204.2
Total	9,788.0	17,089.8	17,120.2
Crude Oil Pipelines & Services:			
Sales of crude oil	9,732.9	19,783.9	20,371.3
Midstream services	573.0	400.4	279.1
Total	10,305.9	20,184.3	20,650.4
Natural Gas Pipelines & Services:			
Sales of natural gas	1,722.6	3,181.7	2,571.6
Midstream services	1,020.7	1,022.1	966.9
Total	2,743.3	4,203.8	3,538.5
Petrochemical & Refined Products Services:			
Sales of petrochemicals and refined products	3,333.5	5,575.5	5,568.8
Midstream services	778.4	741.0	689.7
Total	4,111.9	6,316.5	6,258.5
Offshore Pipelines & Services:			
Sales of natural gas	--	0.3	0.5
Sales of crude oil	3.2	8.6	5.7
Midstream services	75.6	147.9	153.2
Total	78.8	156.8	159.4
Total consolidated revenues	$ 27,027.9	$ 47,951.2	$ 47,727.0
Consolidated costs and expenses			
Operating costs and expenses:			
Cost of sales	$ 19,612.9	$ 40,464.1	$ 40,770.2
Other operating costs and expenses (1)	2,449.4	2,541.8	2,310.4
Depreciation, amortization and accretion	1,428.2	1,282.7	1,148.9
Net losses (gains) attributable to asset sales and insurance recoveries	15.6	(102.1)	(83.4)
Non-cash asset impairment charges	162.6	34.0	92.6
General and administrative costs	192.6	214.5	188.3
Total consolidated costs and expenses	$ 23,861.3	$ 44,435.0	$ 44,427.0

(1) Represents cost of operating our plants, pipelines and other fixed assets, excluding depreciation, amortization and accretion charges.

Fluctuations in our product sales revenues and related cost of sales amounts are explained in part by changes in energy commodity prices. In general, lower energy commodity prices result in a decrease in our revenues attributable to product sales; however, these lower commodity prices also decrease the associated cost of sales as purchase costs decline. The same correlation would be true in the case of higher energy commodity sales prices and purchase costs.

Major Customer Information

Our largest non-affiliated customer for 2015 was Shell Oil Company and its affiliates (collectively, "Shell"), which accounted for $2.0 billion, or 7.4%, of our consolidated revenues for the year. The following table presents our consolidated revenues from Shell by business segment for the year ended December 31, 2015:

NGL Pipelines & Services	$ 400.4
Crude Oil Pipelines & Services	1,335.8
Natural Gas Pipelines & Services	48.6
Petrochemical & Refined Products Services	206.5
Offshore Pipelines & Services	8.0
Total	$ 1,999.3

Shell was also our largest non-affiliated customer for 2014, accounting for 8.5% of our consolidated revenues for the year ended December 31, 2014. BP p.l.c. and its affiliates was our largest non-affiliated customer for 2013, accounting for 9.0% of our consolidated revenues for the year ended December 31, 2013.

Note 11. Earnings Per Unit

Basic earnings per unit is computed by dividing net income or loss available to our common unitholders by the weighted-average number of our distribution-bearing units outstanding during a period, which excludes the Designated Units (see Note 9) to the extent such units do not participate in the distributions to be paid with respect to such period.

Diluted earnings per unit is computed by dividing net income or loss attributable to our limited partners by the sum of (i) the weighted-average number of our distribution-bearing units outstanding during a period (as used in determining basic earnings per unit), (ii) the weighted-average number of our Class B units (see Note 9) outstanding during a period, (iii) the weighted-average number of Designated Units outstanding during a period and (iv) the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net losses, the Class B units, Designated Units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. The dilutive incremental option units are calculated using the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the end of each period are used to repurchase common units at an average market price during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

The following table presents our calculation of basic and diluted earnings per unit for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
BASIC EARNINGS PER UNIT			
Net income attributable to limited partners	$ 2,521.2	$ 2,787.4	$ 2,596.9
Undistributed earnings allocated and cash payments on phantom unit awards (1)	(8.7)	(5.2)	--
Net income available to common unitholders	$ 2,512.5	$ 2,782.2	$ 2,596.9
Basic weighted-average number of common units outstanding	1,966.6	1,848.7	1,788.0
Basic earnings per unit	$ 1.28	$ 1.51	$ 1.45
DILUTED EARNINGS PER UNIT			
Net income attributable to limited partners	$ 2,521.2	$ 2,787.4	$ 2,596.9
Diluted weighted-average number of units outstanding:			
Distribution-bearing common units	1,966.6	1,848.7	1,788.0
Designated Units	26.5	42.7	46.8
Class B units (2)	--	--	5.4
Phantom units (1)	5.4	2.9	--
Incremental option units	0.1	0.9	2.4
Total	1,998.6	1,895.2	1,842.6
Diluted earnings per unit	$ 1.26	$ 1.47	$ 1.41

(1) Each phantom unit award includes a DER, which entitles the recipient to receive cash payments equal to the product of the number of phantom unit awards and the cash distribution per unit paid to our common unitholders. Cash payments made in connection with DERs are nonforfeitable. As a result, the phantom units are considered participating securities for purposes of computing basic earnings per unit. Phantom unit awards were first issued in February 2014.

(2) The Class B units automatically converted into an equal number of distribution-bearing common units in August 2013.

Note 12. Business Combinations

Acquisition of EFS Midstream

In July 2015, we purchased EFS Midstream from affiliates of Pioneer and Reliance for approximately $2.1 billion. The purchase price will be paid in two installments. The first installment of approximately $1.1 billion was paid at closing on July 8, 2015 and the final installment of approximately $1.0 billion will be paid no later than the first anniversary of the closing date. The effective date of the acquisition was July 1, 2015. We funded the cash consideration for the first installment using proceeds from the issuance of short-term notes under our commercial paper program and cash on hand.

The EFS Midstream System provides condensate gathering and processing services as well as gathering, treating and compression services for the associated natural gas. The EFS Midstream System includes approximately 460 miles of gathering pipelines, ten central gathering plants, 119 thousand barrels per day of condensate stabilization capacity and 780 million cubic feet per day of associated natural gas treating capacity. Our primary purpose in acquiring the EFS Midstream System was to secure the underlying production, particularly the processed condensate, for our midstream asset network. Under terms of the associated agreements, Pioneer and Reliance have dedicated certain of their Eagle Ford Shale acreage to us under 20-year, fixed-fee gathering agreements that include minimum volume requirement for the first seven years. Pioneer and Reliance have also entered into related 20-year fee-based agreements with us for natural gas transportation and processing, NGL transportation and fractionation, and for processed condensate and crude oil transportation services.

In connection with the agreements to acquire EFS Midstream, we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for Pioneer and Reliance, if requested by these 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.

We engaged an independent third party business valuation expert to assist us in estimating the fair values of the tangible and intangible assets of EFS Midstream. The following table summarizes our final purchase price allocation for the EFS Midstream acquisition:

Consideration:		
Cash	$	1,069.9
Accrued liability related to EFS Midstream acquisition		986.6
Total consideration	$	2,056.5
Identifiable assets acquired in business combination:		
Current assets, including cash of $13.4 million	$	64.0
Property, plant and equipment		636.0
Customer relationship intangible assets (see Note 7)		1,409.8
Total assets acquired		2,109.8
Liabilities assumed in business combination:		
Current liabilities		(9.6)
Long-term debt		(125.0)
Other long-term liabilities		(1.3)
Total liabilities assumed		(135.9)
Total assets acquired less liabilities assumed		1,973.9
Total consideration given for EFS Midstream		2,056.5
Goodwill (see Note 7)	$	82.6

The estimated fair value of the acquired property, plant and equipment was determined using the cost approach. Of the $636 million of fair value assigned to property, plant and equipment, $366 million was assigned to pipelines and rights of way, $112 million to processing equipment, $84 million to electrical and metering equipment, $42 million to pumps and compressors and $32 million to other assets.

Our consolidated revenues and net income include $117.8 million and $59.9 million, respectively, from EFS Midstream for the six months ended December 31, 2015.

Since the effective date of the EFS Midstream acquisition was July 1, 2015, our Statements of Consolidated Operations do not include earnings from this business prior to this date. The following table presents selected unaudited pro forma earnings information for the years ended December 31, 2015 and 2014 as if the acquisition had been completed on January 1, 2014. This pro forma information was prepared using historical financial data for EFS Midstream and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated financial results would have been for the periods presented had we acquired EFS Midstream on January 1, 2014.

	For the Year Ended December 31,	
	2015	2014
Pro forma earnings data:		
Revenues	$ 27,148.5	$ 48,180.4
Costs and expenses	23,937.1	44,583.6
Operating income	3,585.0	3,856.3
Net income	2,594.4	2,896.1
Net income attributable to noncontrolling interests	37.2	46.1
Net income attributable to limited partners	2,557.2	2,850.0
Basic earnings per unit:		
As reported basic earnings per unit	$ 1.28	$ 1.51
Pro forma basic earnings per unit	$ 1.30	$ 1.54
Diluted earnings per unit:		
As reported diluted earnings per unit	$ 1.26	$ 1.47
Pro forma diluted earnings per unit	$ 1.28	$ 1.50

Acquisition of Oiltanking

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

Oiltanking owned marine terminals located on the Houston Ship Channel and at the Port of Beaumont with a total of 12 ship and barge docks and approximately 26 MMBbls of crude oil and petroleum products storage capacity. Oiltanking’s marine terminal on the Houston Ship Channel is connected by pipeline to our Mont Belvieu, Texas complex and is integral to our growing LPG export, crude oil storage and octane enhancement and propylene businesses. Our ECHO facility is also connected to Oiltanking’s system. We had a strategic relationship and enjoyed mutual growth with Oiltanking and its predecessors since 1983. The combination of our legacy midstream assets and Oiltanking’s access to waterborne markets and crude oil and petroleum products storage assets extended and broadened our midstream energy services business.

We engaged an independent third party business valuation expert to assist us in estimating the fair values of the tangible and intangible assets of Oiltanking. The following table summarizes our final purchase price allocation for the Oiltanking acquisition:

Consideration:		
Cash	$	2,438.3
Equity instruments (54,807,352 common units of Enterprise) (1)		2,171.5
Fair value of total consideration transferred in Step 1	$	4,609.8
Identifiable assets acquired in business combination:		
Current assets, including cash of $21.5 million	$	68.0
Property, plant and equipment		1,080.1
Identifiable intangible assets:		
Customer relationship intangible assets		1,192.4
Contract-based intangible assets		297.5
IDRs (2)		1,459.2
Total identifiable intangible assets		2,949.1
Other assets		227.6
Total assets acquired		4,324.8
Liabilities assumed in business combination:		
Current liabilities		(84.8)
Long-term debt		(223.3)
Other long-term liabilities (3)		(230.0)
Total liabilities assumed		(538.1)
Noncontrolling interest in Oiltanking (4)		(1,397.2)
Total assets acquired less liabilities assumed and noncontrolling interest		2,389.5
Total consideration given for ownership interests in Oiltanking in Step 1		4,609.8
Goodwill (see Note 7)	$	2,220.3

(1) The fair value of the equity-based consideration paid in connection with Step 1 of the Oiltanking acquisition was based on the closing market price of our common units of $39.62 per unit on the acquisition date.

(2) The IDRs represented contractual rights to future cash incentive distributions to be paid by Oiltanking. These rights were granted to Oiltanking GP under the terms of Oiltanking's partnership agreement. Oiltanking GP could separate and sell the IDRs independent of its other residual general partner interest in Oiltanking. In February 2015 (following completion of Step 2 of the Oiltanking acquisition), the Oiltanking IDRs were cancelled and the carrying value of this intangible asset was reclassified to goodwill.

(3) In connection with Step 1, we entered into the Liquidity Option Agreement with OTA and Marquard & Bahls ("M&B", a German corporation and ultimate parent company of OTA). Other long-term liabilities includes $219.7 million for the Liquidity Option Agreement (see Note 17).

(4) From an accounting perspective, Enterprise acquired control of Oiltanking as a result of completing Step 1. The estimated fair value of Oiltanking's common units held by parties other than Enterprise following Step 1 (i.e., the "noncontrolling interest") is based on 28,328,890 common units held by third parties on October 1, 2014 multiplied by the closing unit price for Oiltanking common units of $49.32 per unit on that date.

Although we are not subject to federal income tax, our partners are individually responsible for paying federal income taxes on their share of our taxable income. In deriving our taxable income, the amount assigned to goodwill in this transaction will be amortized over a period of 15 years.

Our consolidated revenues and net income included $57.5 million and $8.1 million, respectively, from Oiltanking for the three months ended December 31, 2014.

We incurred $3.8 million of direct transaction costs in connection with Step 1 of the Oiltanking acquisition in the year ended December 31, 2014. These costs are included in general and administrative costs in the accompanying Statements of Consolidated Operations.

Since the effective date of Step 1 of the Oiltanking acquisition was October 1, 2014, our Statements of Consolidated Operations do not include earnings from this business prior to this date. The following table presents selected unaudited pro forma earnings information for the year ended December 31, 2014 as if the acquisition had been completed on January 1, 2013. This pro forma information was prepared using historical financial data for Oiltanking and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information is not necessarily indicative of what our consolidated financial results would have been for the year ended December 31, 2014 had we acquired Oiltanking on January 1, 2013.

Pro forma earnings data:		
Revenues	$	48,087.5
Costs and expenses		44,509.0
Operating income		3,838.0
Net income		2,877.5
Net income attributable to noncontrolling interests		75.0
Net income attributable to limited partners		2,802.5
Basic earnings per unit:		
As reported basic units outstanding		1,848.7
Pro forma basic units outstanding		1,903.5
As reported basic earnings per unit	$	1.51
Pro forma basic earnings per unit	$	1.47
Diluted earnings per unit:		
As reported diluted units outstanding		1,895.2
Pro forma diluted units outstanding		1,950.0
As reported diluted earnings per unit	$	1.47
Pro forma diluted earnings per unit	$	1.44

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

Step 2 of the Oiltanking acquisition. As a second step ("Step 2") of the Oiltanking acquisition (separately negotiated by the conflicts committee of Oiltanking GP on behalf of Oiltanking), we entered into an Agreement and Plan of Merger (the "merger agreement") with Oiltanking in November 2014 that provided for the following:

- the merger of a wholly owned subsidiary of ours with and into Oiltanking, with Oiltanking surviving the merger as our wholly owned subsidiary; and

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

In accordance with the merger agreement and Oiltanking's partnership agreement, the merger was submitted to a vote of Oiltanking's common unitholders, with the required majority of unitholders (including our ownership interests) voting to approve the merger on February 13, 2015. Upon approval of the merger, a total of 36,827,517 of our common units were issued to Oiltanking's former public unitholders. With the completion of Step 2, total consideration paid by Enterprise for Oiltanking was approximately $6.02 billion.

Since we had a controlling financial interest in Oiltanking before and after completion of Step 2, the increase in our ownership interest in Oiltanking was accounted for as an equity transaction with no gain or loss recognized. Step 2 represented our acquisition of the noncontrolling interests in Oiltanking; therefore, approximately $1.4 billion of noncontrolling interests attributable to Oiltanking were reclassified to limited partners' equity to reflect the February 2015 issuance of 36,827,517 new common units.

Upon completion of the merger, the IDRs of Oiltanking were cancelled since we now own 100% of the future cash flows attributable to the Oiltanking business we acquired. As a result, the $1.46 billion carrying value of the IDR intangible asset was reclassified to goodwill and allocated among our business segments (see Note 7).

See Note 17 for information regarding a Federal Trade Commission ("FTC") inquiry related to the Oiltanking acquisition and our operations.

Note 13. Equity-Based Awards

An allocated portion of the fair value of EPCO's equity-based awards is charged to us under the ASA. The following table summarizes compensation expense we recognized in connection with equity-based awards for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Equity-classified awards:			
Restricted common unit awards	$ 14.7	$ 42.1	$ 71.5
Phantom unit awards	78.3	45.1	--
Unit option awards	--	--	0.8
Liability-classified awards	0.2	0.3	0.5
Total	$ 93.2	$ 87.5	$ 72.8

The fair value of equity-classified awards is amortized into earnings over the requisite service or vesting period. Equity-classified awards are expected to result in the issuance of common units upon vesting. Compensation expense for liability-classified awards is recognized over the requisite service or vesting period based on the fair value of the award remeasured at each reporting date. Liability-classified awards are settled in cash upon vesting.

At December 31, 2015, EPCO's significant long-term incentive plans applicable to us were the Enterprise Products 1998 Long-Term Incentive Plan ("1998 Plan") and the 2008 Enterprise Products Long-Term Incentive Plan (Third Amendment and Restatement) ("2008 Plan"). The 1998 Plan provides for awards of our common units and other rights to our non-employee directors and to employees of EPCO and its affiliates providing services to us. Awards under the 1998 Plan may be granted in the form of unit options, restricted common units, phantom units and distribution equivalent rights ("DERs"). Up to 14,000,000 of our common units may be issued as awards under the 1998 Plan. After giving effect to awards granted under the 1998 Plan through December 31, 2015, a total of 3,073,703 additional common units were available for issuance.

The 2008 Plan (as amended and restated) is a long-term incentive plan under which any employee or consultant of EPCO, us or our affiliates that provides services to us, directly or indirectly, may receive incentive compensation awards in the form of options, restricted common units, phantom units, DERs, unit appreciation rights ("UARs"), unit awards, other unit-based awards or substitute awards. Non-employee directors of our general partner may also participate in the 2008 Plan. The maximum number of common units available for issuance under the 2008 Plan was 30,000,000 at December 31, 2015. This amount automatically increased under the terms of the 2008 Plan by 5,000,000 common units on January 1, 2016 and will continue to automatically increase annually on January 1 thereafter during the term of the 2008 Plan; provided, however, that in no event shall the maximum aggregate number exceed 70,000,000 common units. The 2008 Plan is effective until September 30, 2023 or, if earlier, until the time that all available common units under the 2008 Plan have been delivered to participants or the time of termination of the 2008 Plan by the Board of Directors of EPCO or by the Audit and Conflicts Committee. After giving effect to awards granted under the 2008 Plan through December 31, 2015, a total of 16,669,007 additional common units were available for issuance.

Phantom Unit Awards

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, 2015, 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. The grant date fair value of a phantom unit award is based on the market price per unit of our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period. These awards were first issued in February 2014.

The following table presents phantom unit award activity for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Phantom unit awards at December 31, 2013	--	$ --
Granted (2)	3,530,710	$ 33.12
Vested	(38,200)	$ 33.04
Forfeited	(150,120)	$ 33.12
Phantom unit awards at December 31, 2014	3,342,390	$ 33.13
Granted (3)	3,496,140	$ 33.96
Vested	(940,415)	$ 33.14
Forfeited	(471,166)	$ 33.51
Phantom unit awards at December 31, 2015	5,426,949	$ 33.63

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of phantom unit awards issued during 2014 was $117.0 million based on a grant date market price of our common units ranging from $33.04 to $37.59 per unit. An estimated annual forfeiture rate of 3.4% was applied to these awards.
(3) The aggregate grant date fair value of phantom unit awards issued during 2015 was $118.7 million based on a grant date market price of our common units ranging from $27.31 to $34.40 per unit. An estimated annual forfeiture rate of 3.5% was applied to these awards.

After taking into account tax withholding requirements, we issued 618,395 common units and 23,311 common units in connection with the vesting of phantom unit awards in the years ended December 31, 2015 and 2014, respectively.

Our long-term incentive plans provide for the issuance of DERs in connection with phantom unit awards. A DER entitles the participant 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. Cash payments made in connection with DERs are charged to partners' equity when the phantom unit award is expected to result in the issuance of common units; otherwise, such amounts are expensed.

The following table presents supplemental information regarding our phantom unit awards and DERs for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Cash payments made in connection with DERs	$ 7.7	$ 3.7	$ --
Total intrinsic value of phantom unit awards that vested during period	$ 31.2	$ 1.4	$ --

For the EPCO group of companies, the unrecognized compensation cost associated with phantom unit awards was $77.0 million at December 31, 2015, of which our share of the cost is currently estimated to be $69.2 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 2.0 years.

Restricted Common Unit Awards

Restricted common 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. Restricted common 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. Restricted common units are included in the number of common units outstanding as presented on our Consolidated Balance Sheets.

The fair value of a restricted common unit award is based on the market price per unit of our common units on the date of grant. Compensation expense is recognized based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents restricted common unit award activity for the periods indicated:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit (1)
Restricted common units at December 31, 2012	7,786,972	$ 20.43
Granted (2)	3,549,052	$ 28.61
Vested	(3,770,696)	$ 17.48
Forfeited	(344,114)	$ 23.82
Restricted common units at December 31, 2013	7,221,214	$ 25.83
Vested	(2,634,074)	$ 23.94
Forfeited	(357,350)	$ 26.38
Restricted common units at December 31, 2014	4,229,790	$ 26.96
Vested	(2,009,970)	$ 26.00
Forfeited	(259,300)	$ 27.53
Restricted common units at December 31, 2015	1,960,520	$ 27.88

(1) Determined by dividing the aggregate grant date fair value of awards (before an allowance for forfeitures) by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued during 2013 was $101.5 million based on a grant date market price of our common units ranging from $28.56 to $31.74 per unit. An estimated annual forfeiture rate of 3.9% was applied to these awards.

Each recipient of a restricted common unit award is entitled to nonforfeitable cash distributions equal to the product of the number of restricted common units outstanding for the participant and the cash distribution per unit paid to our common unitholders. These distributions are included in “Cash distributions paid to limited partners” as presented on our Statements of Consolidated Cash Flows.

The following table presents supplemental information regarding our restricted common unit awards for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Cash distributions paid to restricted common unitholders	$ 4.0	$ 7.3	$ 10.6
Total intrinsic value of restricted common unit awards that vested during period	$ 67.3	$ 87.1	$ 109.9

For the EPCO group of companies, the unrecognized compensation cost associated with restricted common unit awards was an aggregate $7.2 million at December 31, 2015, of which our share of the cost is currently estimated to be $5.7 million. Due to the graded vesting provisions of these awards, we expect to recognize our share of the unrecognized compensation cost for these awards over a weighted-average period of 1.0 year.

Unit Option Awards

EPCO’s long-term incentive plans provide for the issuance of non-qualified incentive options denominated in our common units. All of our unit option awards had been exercised as of December 31, 2015 and no new unit option awards were granted during the three years ended December 31, 2015. When issued, the exercise price of each unit option award was equal to the market price of our common units on the date of grant. In general, unit option awards had a vesting period of four years from the date of grant and expired at the end of the calendar year following the year of vesting. The fair value of each unit option award was estimated on the date of grant using a Black-Scholes option pricing model, which incorporated various assumptions including expected life of the option, risk-free interest rates, expected distribution yield of our common units, and expected price volatility of our common units. Compensation expense recorded in connection with unit option awards was based on the grant date fair value, net of an allowance for estimated forfeitures, over the requisite service or vesting period.

The following table presents unit option award activity for the periods indicated:

	Number of Units	Weighted-Average Strike Price (dollars/unit)
Unit option awards at December 31, 2012	5,522,280	$ 13.71
Exercised	(1,472,280)	$ 14.98
Unit option awards at December 31, 2013	4,050,000	$ 13.24
Exercised	(2,720,000)	$ 11.83
Forfeited	(60,000)	$ 16.14
Unit option awards at December 31, 2014 (1)	1,270,000	$ 16.14
Exercised	(1,270,000)	$ 16.14
Unit option awards at December 31, 2015	--	$ --

(1) All of the unit option awards outstanding at December 31, 2014 vested during 2014 and were exercised during 2015.

In order to fund its unit option award-related obligations, EPCO purchased our common units at fair value directly from us. When employees exercise unit option awards, we reimburse EPCO for the cash difference between the strike price paid by the employee and the actual purchase price paid by EPCO for the units issued to the employee.

The following table presents supplemental information regarding our unit option awards during the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Total intrinsic value of unit option awards exercised during period	$ 21.7	$ 57.5	$ 19.8
Cash received from EPCO in connection with the exercise of unit option awards	$ 13.1	$ 33.4	$ 11.5
Unit option award-related cash reimbursements to EPCO	$ 21.7	$ 57.5	$ 19.8

As of December 31, 2015, all compensation expense related to unit option awards had been recognized.

Note 14. Derivative Instruments, Hedging Activities and Fair Value Measurements

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, options and other instruments with similar characteristics. Substantially all of our derivatives are used for non-trading activities.

Interest Rate Hedging Activities

We may utilize interest rate swaps, forward starting swaps and similar derivative instruments to manage our exposure to changes in interest rates charged on borrowings under certain consolidated debt agreements. This strategy may be used in controlling our overall cost of capital associated with such borrowings.

The following table summarizes our portfolio of interest rate swaps at December 31, 2015:

Hedged Transaction	Number and Type of Derivatives Outstanding	Notional Amount	Period of Hedge	Rate Swap	Accounting Treatment
Senior Notes OO	10 fixed-to-floating swaps	$750.0	5/2015 to 5/2018	1.65% to 0.82%	Fair value hedge

As a result of market conditions in 2014, we elected to terminate all of our interest rate swaps then outstanding. Since these interest rate swaps were accounted for as fair value hedges, the aggregate $27.6 million of gains was recorded as a component of long-term debt and is being amortized to earnings (as a decrease in interest expense) using the effective interest method over the remaining life of the associated debt obligations. Of the total gain, $17.6 million was amortized through January 2016 and $10.0 million will be amortized through October 2019.

In connection with the issuance of senior notes during 2013, we settled 16 forward starting swaps having an aggregate notional amount of $1.0 billion, which resulted in cash losses totaling $168.8 million. As cash flow hedges, losses on these derivative instruments are a component of accumulated other comprehensive loss and are being amortized into earnings (as an increase in interest expense) over the remaining life of the associated debt obligations using the effective interest method. The $168.8 million loss will be amortized into earnings through March 2023.

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, 2015 (volume measures as noted):

	Volume (1)		**Accounting**
Derivative Purpose	**Current** (2)	**Long-Term** (2)	**Treatment**
Derivatives designated as hedging instruments:			
Natural gas processing:			
Forecasted natural gas purchases for plant thermal reduction (Bcf)	9.1	n/a	Cash flow hedge
Forecasted sales of NGLs (MMBbls)	2.1	n/a	Cash flow hedge
Natural gas marketing:			
Forecasted purchases of natural gas for fuel (Bcf)	2.4	n/a	Cash flow hedge
Natural gas storage inventory management activities (Bcf)	10.7	n/a	Fair value hedge
NGL marketing:			
Forecasted purchases of NGLs and related hydrocarbon products (MMBbls)	28.7	0.4	Cash flow hedge
Forecasted sales of NGLs and related hydrocarbon products (MMBbls)	42.2	0.1	Cash flow hedge
Refined products marketing:			
Forecasted purchases of refined products (MMBbls)	2.7	n/a	Cash flow hedge
Forecasted sales of refined products (MMBbls)	0.8	0.1	Cash flow hedge
Refined products inventory management activities (MMBbls)	1.3	n/a	Fair value hedge
Crude oil marketing:			
Forecasted purchases of crude oil (MMBbls)	15.0	n/a	Cash flow hedge
Forecasted sales of crude oil (MMBbls)	17.6	n/a	Cash flow hedge
Crude oil inventory management activities (MMBbls)	0.7	n/a	Fair value hedge
Derivatives not designated as hedging instruments:			
Natural gas risk management activities (Bcf) (3,4)	48.2	8.2	Mark-to-market
NGL risk management activities (MMBbls) (4)	1.8	n/a	Mark-to-market
Crude oil risk management activities (MMBbls) (4)	11.8	n/a	Mark-to-market

(1) Volume for derivatives designated as hedging instruments reflects the total amount of volumes hedged whereas volume for derivatives not designated as hedging instruments reflects the absolute value of derivative notional volumes.
(2) The maximum term for derivatives designated as cash flow hedges, derivatives designated as fair value hedges and derivatives not designated as hedging instruments is December 2017, January 2017 and March 2018, respectively.
(3) Current and long-term volumes include 24.3 Bcf and 2.1 Bcf, respectively, 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, 2015, 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 forward contracts and derivative instruments.

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

- 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 forward contracts and derivative instruments.

Certain basis swaps, basis spread options and other derivative instruments not designated as hedging instruments are used to manage market risks associated with anticipated purchases and sales of commodity products. There is some uncertainty involved in the timing of these transactions often due to the development of more favorable profit opportunities or when spreads are insufficient to cover variable costs thus reducing the likelihood that the transactions will occur during the periods originally forecasted. In accordance with derivatives accounting guidance, these instruments do not qualify for hedge accounting even though they are effective at managing the risk exposures of the underlying assets. Due to volatility in commodity prices, any non-cash, mark-to-market earnings variability cannot be predicted.

Tabular Presentation of Fair Value Amounts, and Gains and Losses on Derivative Instruments and Related Hedged Items

The following table provides a balance sheet overview of our derivative assets and liabilities at the dates indicated:

	Asset Derivatives				Liability Derivatives			
	December 31, 2015		December 31, 2014		December 31, 2015		December 31, 2014	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments								
Interest rate derivatives	Current assets	$ 3.2	Current assets	$ --	Other current liabilities	$ --	Other current liabilities	$ --
Interest rate derivatives	Other assets	--	Other assets	--	Other liabilities	3.7	Other liabilities	--
Total interest rate derivatives		3.2		--		3.7		--
Commodity derivatives	Current assets	253.8	Current assets	217.9	Other current liabilities	137.5	Other current liabilities	145.3
Commodity derivatives	Other assets	0.2	Other assets	--	Other liabilities	1.4	Other liabilities	--
Total commodity derivatives		254.0		217.9		138.9		145.3
Total derivatives designated as hedging instruments		$ 257.2		$ 217.9		$ 142.6		$ 145.3
Derivatives not designated as hedging instruments								
Interest rate derivatives	Current assets	$ --	Current assets	$ --	Other current liabilities	$ --	Other current liabilities	$ --
Commodity derivatives	Current assets	1.6	Current assets	8.1	Other current liabilities	3.1	Other current liabilities	0.7
Commodity derivatives	Other assets	--	Other assets	0.6	Other liabilities	1.0	Other liabilities	1.4
Total commodity derivatives		1.6		8.7		4.1		2.1
Total derivatives not designated as hedging instruments		$ 1.6		$ 8.7		$ 4.1		$ 2.1

Certain of our commodity derivative instruments are subject to master netting arrangements or similar agreements. The following tables present our derivative instruments subject to such arrangements at the dates indicated:

	Offsetting of Financial Assets and Derivative Assets						
				Gross Amounts Not Offset in the Balance Sheet			
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Amounts of Assets Presented in the Balance Sheet	Financial Instruments	Cash Collateral Paid	Cash Collateral Received	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)			(v) = (iii) + (iv)
As of December 31, 2015:							
Interest rate derivatives	$ 3.2	$ --	$ 3.2	$ (3.2)	$ --	$ --	$ --
Commodity derivatives	255.6	--	255.6	(143.0)	(40.1)	(72.2)	0.3
As of December 31, 2014:							
Commodity derivatives	$ 226.6	$ --	$ 226.6	$ (147.3)	$ --	$ (23.9)	$ 55.4

	Offsetting of Financial Liabilities and Derivative Liabilities					
				Gross Amounts Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Liabilities Presented in the Balance Sheet	Financial Instruments	Cash Collateral Paid	Amounts That Would Have Been Presented On Net Basis
	(i)	(ii)	(iii) = (i) – (ii)	(iv)		(v) = (iii) + (iv)
As of December 31, 2015:						
Interest rate derivatives	$ 3.7	$ --	$ 3.7	$ (3.2)	$ --	$ 0.5
Commodity derivatives	143.0	--	143.0	(143.0)	--	--
As of December 31, 2014:						
Commodity derivatives	$ 147.4	$ --	$ 147.4	$ (147.3)	$ --	$ 0.1

Derivative assets and liabilities recorded on our Consolidated Balance Sheets are presented on a gross-basis and determined at the individual transaction level. This presentation method is applied regardless of whether the respective exchange clearing agreements, counterparty contracts or master netting agreements contain netting language often referred to as “rights of offset.” Although derivative amounts are presented on a gross-basis, having rights of offset enable the settlement of a net as opposed to gross receivable or payable amount under a counterparty default or liquidation scenario.

Cash is paid and received as collateral under certain agreements, particularly for those associated with exchange transactions. For any cash collateral payments or receipts, corresponding assets or liabilities are recorded to reflect the variation margin deposits or receipts with exchange clearing brokers and customers. These balances are also presented on a gross-basis on our Consolidated Balance Sheets.

The tabular presentation above provides a means for comparing the gross amount of derivative assets and liabilities, excluding associated accounts payable and receivable, to the net amount that would likely be receivable or payable under a default scenario based on the existence of rights of offset in the respective derivative agreements. Any cash collateral paid or received is reflected in these tables, but only to the extent that it represents variation margins. Any amounts associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from these tables.

The following tables present the effect of our derivative instruments designated as fair value hedges on our Statements of Consolidated Operations for the periods indicated:

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative		
		For the Year Ended December 31,		
		2015	2014	2013
Interest rate derivatives	Interest expense	$ (1.4)	$ (26.5)	$ (13.1)
Commodity derivatives	Revenue	19.1	11.9	(0.1)
Total		$ 17.7	$ (14.6)	$ (13.2)

Derivatives in Fair Value Hedging Relationships	Location	Gain (Loss) Recognized in Income on Hedged Item		
		For the Year Ended December 31,		
		2015	2014	2013
Interest rate derivatives	Interest expense	$ 1.4	$ 26.4	$ 12.8
Commodity derivatives	Revenue	0.2	(11.8)	(5.7)
Total		$ 1.6	$ 14.6	$ 7.1

With respect to our derivative instruments designated as fair value hedges, amounts attributable to ineffectiveness and those excluded from the assessment of hedge effectiveness were not material to our consolidated financial statements during the periods presented.

The following tables present the effect of our derivative instruments designated as cash flow hedges on our Statements of Consolidated Operations and Statements of Consolidated Comprehensive Income for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Change in Value Recognized in Other Comprehensive Income (Loss) On Derivative (Effective Portion)		
	For the Year Ended December 31,		
	2015	2014	2013
Interest rate derivatives	$ --	$ --	$ 6.6
Commodity derivatives – Revenue (1)	217.6	161.3	(47.9)
Commodity derivatives – Operating costs and expenses (1)	(2.7)	--	1.0
Total	$ 214.9	$ 161.3	$ (40.3)

(1) The fair value of these derivative instruments will be reclassified to their respective locations on the Statement of Consolidated Operations upon settlement of the underlying derivative transactions, as appropriate.

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) to Income (Effective Portion)		
		For the Year Ended December 31,		
		2015	2014	2013
Interest rate derivatives	Interest expense	$ (35.3)	$ (32.4)	$ (29.2)
Commodity derivatives	Revenue	231.7	75.0	(22.4)
Commodity derivatives	Operating costs and expenses	(3.5)	1.7	0.3
Total		$ 192.9	$ 44.3	$ (51.3)

Derivatives in Cash Flow Hedging Relationships	Location	Gain (Loss) Recognized in Income on Derivative (Ineffective Portion)		
		For the Year Ended December 31,		
		2015	2014	2013
Commodity derivatives	Revenue	$ 4.7	$ (0.3)	$ 0.2
Commodity derivatives	Operating costs and expenses	0.1	--	--
Total		$ 4.8	$ (0.3)	$ 0.2

Over the next twelve months, we expect to reclassify $37.4 million of losses attributable to interest rate derivative instruments from accumulated other comprehensive loss to earnings as an increase in interest expense. Likewise, we expect to reclassify $57.6 million of net gains attributable to commodity derivative instruments from accumulated other comprehensive income to earnings, $57.3 million as an increase in revenue and $0.3 million as a decrease to operating costs and expenses.

The following table presents the effect of our derivative instruments not designated as hedging instruments on our Statements of Consolidated Operations for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location	Gain (Loss) Recognized in Income on Derivative		
		For the Year Ended December 31,		
		2015	2014	2013
Interest rate derivatives	Interest expense	$ --	$ (0.1)	$ (0.7)
Commodity derivatives	Revenue	1.0	(23.0)	7.3
Commodity derivatives	Operating costs and expense	0.1	--	--
Total		$ 1.1	$ (23.1)	$ 6.6

Fair Value Measurements

The following tables set forth, by level within the Level 1, 2 and 3 fair value hierarchy (see Note 2), the carrying values of our financial assets and liabilities at the dates indicated. These assets and liabilities are measured on a recurring basis and are classified based on the lowest level of input used to estimate their fair value. Our assessment of the relative significance of such inputs requires judgment.

	December 31, 2015 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Interest rate derivatives	$ --	$ 3.2	$ --	$ 3.2
Commodity derivatives	109.5	145.2	0.9	255.6
Total	$ 109.5	$ 148.4	$ 0.9	$ 258.8
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 245.1	$ 245.1
Interest rate derivatives	--	3.7	--	3.7
Commodity derivatives	31.3	109.2	2.5	143.0
Total	$ 31.3	$ 112.9	$ 247.6	$ 391.8

	December 31, 2014 Fair Value Measurements Using			
	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Financial assets:				
Commodity derivatives	$ 37.8	$ 187.8	$ 1.0	$ 226.6
Financial liabilities:				
Liquidity Option Agreement	$ --	$ --	$ 219.7	$ 219.7
Commodity derivatives	13.8	133.0	0.6	147.4
Total	$ 13.8	$ 133.0	$ 220.3	$ 367.1

The following table sets forth a reconciliation of changes in the fair values of our recurring Level 3 financial assets and liabilities on a combined basis for the periods indicated:

	Location	For the Year Ended December 31, 2015	2014
Financial asset (liability) balance, net, January 1		$ (219.3)	$ 3.2
Total gains (losses) included in:			
Net income (1)	Revenue	(0.9)	0.9
Net income	Other expense, net	(25.4)	--
Other comprehensive income (loss)	Commodity derivative instruments – changes in fair value of cash flow hedges	(19.2)	(2.6)
Settlements		0.1	(3.4)
Acquisition of Liquidity Option Agreement (see Note 17)		--	(219.7)
Transfers out of Level 3 (2)		18.0	2.3
Financial liability balance, net, December 31 (2)		$ (246.7)	$ (219.3)

(1) There were $0.9 million and $2.6 million of unrealized losses included in these amounts for the years ended December 31, 2015 and 2014, respectively.
(2) Transfers out of Level 3 into Level 2 were due to shorter remaining transaction maturities falling inside of the Level 2 range at December 31, 2015 and 2014.

The following tables provide quantitative information regarding our recurring Level 3 fair value measurements for commodity derivatives at the dates indicated:

	Fair Value At December 31, 2015				
	Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 0.9	$ 1.2	Discounted cash flow	Forward commodity prices	$35.63-$43.84/barrel
Commodity derivatives – Propane	--	1.3	Discounted cash flow	Forward commodity prices	$0.42-$0.44/gallon
Total	$ 0.9	$ 2.5			

	Fair Value At December 31, 2014				
	Financial Assets	Financial Liabilities	Valuation Techniques	Unobservable Input	Range
Commodity derivatives – Crude oil	$ 1.0	$ 0.4	Discounted cash flow	Forward commodity prices	$49.26-$53.27/barrel
Commodity derivatives – Natural gas	--	0.2	Discounted cash flow	Forward commodity prices	$3.05-$4.09/MMBtu
Total	$ 1.0	$ 0.6			

With respect to commodity derivatives, we believe forward commodity prices are the most significant unobservable inputs in determining our Level 3 recurring fair value measurements at December 31, 2015. In general, changes in the price of the underlying commodity increases or decreases the fair value of a commodity derivative depending on whether the derivative was purchased or sold. We generally expect changes in the fair value of our derivative instruments to be offset by corresponding changes in the fair value of our hedged exposures.

The recurring fair value measurement pertaining to the Liquidity Option Agreement is based on a number of Level 3 inputs. See Note 17 for a discussion of this liability.

Nonrecurring Fair Value Measurements

We measure certain assets, primarily long-lived assets and equity method investments, at fair value on a nonrecurring basis. These assets are recognized at fair value when they are deemed to be other-than-temporarily impaired. The following table summarizes our non-cash impairment charges by segment during each of the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
NGL Pipelines & Services	$ 20.8	$ 16.2	$ 30.6
Crude Oil Pipelines & Services	33.5	2.9	30.1
Natural Gas Pipelines & Services	21.6	0.7	--
Petrochemical & Refined Products Services	28.2	9.1	18.7
Offshore Pipelines & Services	58.5	5.1	18.0
Total	$ 162.6	$ 34.0	$ 97.4

As presented in the following tables, our estimated fair values were based on management's expectation of the market values for such assets based on their knowledge and experience in the industry (a Level 3 type measure involving significant unobservable inputs). In many cases, there are no active markets (Level 1) or other similar recent transactions (Level 2) to compare to. Our assumptions used in such analyses are based on the highest and best use of the asset and includes estimated probabilities where multiple cash flow outcomes are possible.

When probability weights are used, the weights are generally obtained from business management personnel having oversight responsibilities for the assets being tested. Key commercial assumptions (e.g., anticipated operating margins, throughput or processing volume growth rates, timing of cash flows, etc.) that represent Level 3 unobservable inputs and test results are reviewed and certified by members of senior management.

Our non-cash asset impairment charges for the year ended December 31, 2015 are a component of operating costs and expenses and primarily reflect the $54.8 million charge we recorded in connection with the sale of our Offshore Business (see Note 5) and the abandonment of certain natural gas and crude oil pipeline assets in Texas. The following table presents categories of long-lived assets, primarily property, plant and equipment, that were subject to non-recurring fair value measurements during the year ended December 31, 2015:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at December 31, 2015	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Long-lived assets disposed of other than by sale	$ 0.4	$ --	$ --	$ 0.4	$ 81.4
Long-lived assets held for sale	18.0	--	--	18.0	14.2
Long-lived assets disposed of by sale (1)	--	--	--	--	67.0
Total					$ 162.6

(1) Includes a $54.8 million charge recorded in connection with the sale of our Offshore Business.

Our non-cash asset impairment charges for the year ended December 31, 2014 are a component of operating costs and expenses and primarily relate to the abandonment of certain natural gas processing equipment in Louisiana, natural gas pipeline segments in the Gulf of Mexico, refined products terminal and pipeline assets in Arkansas, and NGL storage caverns in Oklahoma and Texas. The following table presents categories of long-lived assets, primarily property, plant and equipment, that were subject to non-recurring fair value measurements during the year ended December 31, 2014:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at December 31, 2014	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 26.7
Long-lived assets held for sale	1.5	--	--	1.5	3.6
Long-lived assets disposed of by sale	--	--	--	--	3.7
Total					$ 34.0

Our non-cash asset impairment charges for the year ended December 31, 2013 primarily relate to the abandonment of certain crude oil and natural gas pipeline segments in Texas, Oklahoma and the Gulf of Mexico, certain refined products terminal assets in Texas, an NGL storage cavern in Arizona and an NGL fractionator and storage cavern facility in Ohio. These impairment charges totaled $92.6 million and are a component of operating costs and expenses. The remaining charge, or $4.8 million, relates to the impairment of an equity method investment and was presented as a component of equity in income of unconsolidated affiliates. The following table presents categories of long-lived assets that were subject to non-recurring fair value measurements during the year ended December 31, 2013:

		Fair Value Measurements at the End of the Reporting Period Using			
	Carrying Value at December 31, 2013	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Non-Cash Impairment Loss
Long-lived assets disposed of other than by sale	$ --	$ --	$ --	$ --	$ 79.4
Long-lived assets held and used	44.6	--	--	44.6	9.0
Long-lived assets held for sale	0.6	--	--	0.6	3.4
Long-lived assets disposed of by sale	--	--	--	--	5.6
Total					$ 97.4

Other Fair Value Information

The carrying amounts of cash and cash equivalents (including restricted cash balances), accounts receivable, commercial paper notes and accounts payable approximate their fair values based on their short-term nature. The estimated total fair value of our fixed-rate debt obligations was $19.51 billion and $22.16 billion at December 31, 2015 and 2014, respectively. The aggregate carrying value of these debt obligations was $20.87 billion and $20.48 billion at December 31, 2015 and 2014, respectively. These values are based on quoted market prices for such debt or debt of similar terms and maturities (Level 2), our credit standing and the credit standing of our counterparties. Changes in market rates of interest affect the fair value of our fixed-rate debt. The amounts reported for fixed-rate debt obligations as of December 31, 2015, exclude those amounts hedged using fixed-to-floating interest rate swaps. See "*Interest Rate Hedging Activities*" within this Note 14 for additional information. The carrying values of our variable-rate long-term debt obligations approximate their fair values since the associated interest rates are market-based. We do not have any long-term investments in debt or equity securities recorded at fair value.

Note 15. Related Party Transactions

The following table summarizes our related party transactions for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Revenues – related parties:			
Unconsolidated affiliates	$ 72.3	$ 71.5	$ 65.9
Costs and expenses – related parties:			
EPCO and its privately held affiliates	$ 949.3	$ 939.9	$ 892.2
Unconsolidated affiliates	245.3	183.0	160.0
Total	$ 1,194.6	$ 1,122.9	$ 1,052.2

The following table summarizes our related party accounts receivable and accounts payable balances at the dates indicated:

	December 31,	
	2015	2014
Accounts receivable - related parties:		
Unconsolidated affiliates	$ 1.2	$ 2.8
Accounts payable - related parties:		
EPCO and its privately held affiliates	$ 75.6	$ 98.1
Unconsolidated affiliates	8.5	20.8
Total	$ 84.1	$ 118.9

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.

Relationship with EPCO and Affiliates

We have an extensive and ongoing relationship with EPCO and its privately held affiliates (including Enterprise GP, our general partner), which are not a part of our consolidated group of companies.

At December 31, 2015, EPCO and its privately held affiliates (including Dan Duncan LLC and certain Duncan family trusts) beneficially owned the following limited partner interests in us:

Total Number of Units	Percentage of Total Units Outstanding
677,159,667	33.6%

Of the total number of units held by EPCO and its privately held affiliates, 118,000,000 have been pledged as security under the credit facilities of certain of the privately held affiliates at December 31, 2015. These credit facilities contain customary and other events of default, including defaults by us and other affiliates of EPCO. An event of default, followed by a foreclosure on the pledged collateral, could ultimately result in a change in ownership of these units and affect the market price of our common units.

We and Enterprise GP are both separate legal entities apart from each other and apart from EPCO and its other affiliates, with assets and liabilities that are also separate from those of EPCO and its other affiliates. EPCO and its privately held affiliates depend on the cash distributions they receive from us and other investments to fund their other activities and to meet their debt obligations. During the years ended December 31, 2015, 2014 and 2013, we paid EPCO and its privately held affiliates cash distributions totaling $948.3 million, $877.0 million and $811.4 million, respectively. Distributions paid during the years ended December 31, 2015, 2014 and 2013 excluded 35,380,000, 45,120,000 and 47,400,000 Designated Units, respectively (see Note 9).

From time-to-time, EPCO and its privately held affiliates elect to reinvest a portion of the cash distributions received from us into the purchase of additional common units under our DRIP. These purchases totaled $100 million for each of the years ended December 31, 2015 and 2014. In March 2015, a privately held affiliate of EPCO purchased 3,225,057 common units from us under our ATM program for $31.01 per unit.

In January 2016, privately held affiliates of EPCO purchased 3,830,256 common units from us under our ATM program, generating gross proceeds of $100 million. In February 2016, privately held affiliates of EPCO reinvested an additional $100 million in us, resulting in the issuance of 4,481,504 of our common units under our DRIP. See Note 9 for additional information regarding our DRIP and ATM program.

We lease office space from affiliates of EPCO. The rental rates in these lease agreements approximate market rates.

EPCO ASA. We have no employees. All of our operating functions and general and administrative support services are provided by employees of EPCO pursuant to the ASA or by other service providers. We and our general partner are parties to the ASA. The significant terms of the ASA are as follows:

- EPCO will provide selling, general and administrative services and management and operating services as may be necessary to manage and operate our businesses, properties and assets (all in accordance with prudent industry practices). EPCO will employ or otherwise retain the services of such personnel.

- We are required to reimburse EPCO for its services in an amount equal to the sum of all costs and expenses incurred by EPCO which are directly or indirectly related to our business or activities (including expenses reasonably allocated to us by EPCO). In addition, we have agreed to pay all sales, use, excise, value added or similar taxes, if any, that may be applicable from time to time with respect to the services provided to us by EPCO.

- EPCO will allow us to participate as a named insured in its overall insurance program, with the associated premiums and other costs being allocated to us. See Note 18 for additional information regarding our insurance programs.

Our operating costs and expenses include amounts paid to EPCO for the costs it incurs to operate our facilities, including the compensation of its employees. We reimburse EPCO for actual direct and indirect expenses it incurs related to the operation of our assets. Likewise, our general and administrative costs include amounts paid to EPCO for administrative services, including the compensation of its employees. In general, our reimbursement to EPCO for administrative services is either (i) on an actual basis for direct expenses it may incur on our behalf (e.g., the purchase of office supplies) or (ii) based on an allocation of such charges between the various parties to the ASA based on the estimated use of such services by each party (e.g., the allocation of legal or accounting salaries based on estimates of time spent on each entity's business and affairs).

The following table presents our related party costs and expenses attributable to the ASA with EPCO for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Operating costs and expenses	$ 826.4	$ 801.6	$ 770.6
General and administrative expenses	105.2	121.7	105.2
Total costs and expenses	$ 931.6	$ 923.3	$ 875.8

Since the vast majority of such expenses are charged to us on an actual basis (i.e., no mark-up or subsidy is charged or received by EPCO), we believe that such expenses are representative of what the amounts would have been on a standalone basis. With respect to allocated costs, we believe that the proportional direct allocation method employed by EPCO is reasonable and reflective of the estimated level of costs we would have incurred on a standalone basis.

Relationships with Unconsolidated Affiliates

Many of our unconsolidated affiliates perform supporting or complementary roles to our other business operations. The following information summarizes significant related party transactions with our current unconsolidated affiliates:

- For the years ended December 31, 2015, 2014 and 2013, we paid Seaway $175.8 million, $130.8 million and $132.4 million, respectively, for pipeline transportation and storage services in connection with our crude oil marketing activities. Revenues from Seaway were $47.7 million, $29.4 million and $41.3 million for the years ended December 31, 2015, 2014 and 2013, respectively.

- We pay Promix for the transportation, storage and fractionation of NGLs. In addition, we sell natural gas to Promix for its plant fuel requirements. Revenues from Promix were $8.8 million, $11.1 million and $9.8 million for the years ended December 31, 2015, 2014 and 2013, respectively. Expenses with Promix were $24.9 million, $25.8 million and $28.1 million for the years ended December 31, 2015, 2014 and 2013, respectively.

- For the years ended December 31, 2015, 2014 and 2013, we paid Eagle Ford Crude Oil Pipeline $39.4 million, $25.8 million and $5.4 million, respectively, for crude oil transportation.

- We perform management services for certain of our unconsolidated affiliates. We charged such affiliates $19.1 million, $24.5 million and $21.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Note 16. Provision for Income Taxes

Publicly traded partnerships like ours are treated as corporations unless they have 90% or more in qualifying income (as that term is defined in the Internal Revenue Code). We satisfied this requirement in each of the years ended December 31, 2015, 2014 and 2013 and, as a result, are not subject to federal income tax. However, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Net earnings for financial reporting purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and financial reporting basis of certain assets and liabilities and other factors. We do not have access to information regarding each partner's individual tax basis in our limited partner interests.

Provision for income taxes primarily reflects our state tax obligations under the Revised Texas Franchise Tax (the "Texas Margin Tax"). Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

Our federal, state and foreign income tax provision (benefit) is summarized below:

	For the Year Ended December 31,		
	2015	2014	2013
Current:			
Federal	$ 0.9	$ 2.2	$ (0.5)
State	15.5	13.4	19.3
Foreign	1.7	1.4	0.8
Total current	18.1	17.0	19.6
Deferred:			
Federal	(1.4)	2.2	(0.5)
State	(19.2)	3.5	38.9
Foreign	--	0.4	(0.5)
Total deferred	(20.6)	6.1	37.9
Total provision for (benefit from) income taxes	$ (2.5)	$ 23.1	$ 57.5

A reconciliation of the provision for (benefit from) income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income before income taxes is as follows:

	For the Year Ended December 31,		
	2015	2014	2013
Pre-Tax Net Book Income ("NBI")	$ 2,555.9	$ 2,856.6	$ 2,664.6
Texas Margin Tax (1)	$ (3.7)	$ 17.5	$ 58.3
State income taxes (net of federal benefit)	0.7	0.2	(0.1)
Federal income taxes computed by applying the federal statutory rate to NBI of corporate entities	1.1	1.5	(1.4)
Expiration of tax net operating loss	--	--	0.1
Other permanent differences	(0.6)	3.9	0.6
Provision for (benefit from) income taxes	$ (2.5)	$ 23.1	$ 57.5
Effective income tax rate	(0.1)%	0.8%	2.2%

(1) Although the Texas Margin Tax is not considered a state income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers our Texas-sourced revenues and expenses. During 2015, certain legislative changes were enacted to the Texas Margin Tax, which reduced the tax rate for business entities that operate within the state.

The following table presents the significant components of deferred tax assets and deferred tax liabilities at the dates indicated:

	December 31,	
	2015	2014
Deferred tax assets:		
Net operating loss carryovers (1)	$ 0.2	$ 0.3
Accruals	1.6	1.8
Total deferred tax assets	1.8	2.1
Less: Deferred tax liabilities:		
Property, plant and equipment	44.9	64.4
Equity investment in partnerships	2.7	4.1
Total deferred tax liabilities	47.6	68.5
Total net deferred tax liabilities	$ 45.8	$ 66.4
Current portion of total net deferred tax assets	$ 0.3	$ 0.2
Long-term portion of total net deferred tax liabilities	$ 46.1	$ 66.6

(1) These losses expire in various years between 2016 and 2033 and are subject to limitations on their utilization.

Accounting guidance provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. We did not rely on any uncertain tax positions in recording our income tax-related amounts during the years ended December 31, 2015, 2014 or 2013.

Note 17. Commitments and Contingencies

Litigation

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.

Management has regular quarterly litigation reviews, including updates from legal counsel, to assess the possible need for accounting recognition and disclosure of these contingencies. We accrue an undiscounted liability for those contingencies where the loss is probable and the amount can be reasonably estimated. If a range of probable loss amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum amount in 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. Based on a consideration of all relevant known facts and circumstances, we do not believe that the ultimate outcome of any currently pending litigation directed against us will have a material impact on our consolidated financial statements either individually at the claim level or in the aggregate.

At December 31, 2015 and 2014, our accruals for litigation contingencies were $4.6 million and $2.4 million, respectively, and were recorded in our Consolidated Balance Sheets as a component of "Other current liabilities." Our evaluation of litigation contingencies is based on the facts and circumstances of each case and predicting the outcome of these matters involves uncertainties. In the event the assumptions we use to evaluate these matters change in future periods or new information becomes available, we may be required to record additional accruals. In an effort to mitigate expenses associated with litigation, we may settle legal proceedings out of court.

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

In September 2011, ETP filed suit against us and a third party in connection with the cancelled project alleging, among other things, that we and ETP had formed a "partnership." The case was tried in the District Court of Dallas County, Texas, 298th Judicial District. While we firmly believe, and argued during our defense, that no agreement was ever executed forming a legal joint venture or partnership between the parties, the jury found that the actions of the two companies, nevertheless, constituted a legal partnership. As a result, the jury found that ETP was wrongfully excluded from a subsequent pipeline project involving a third party, and awarded ETP $319.4 million in actual damages on March 4, 2014. On July 29, 2014, the court entered judgment against us in an aggregate amount of $535.8 million, which includes (i) $319.4 million as the amount of actual damages awarded by the jury, (ii) an additional $150.0 million in disgorgement for the alleged benefit we received due to a breach of fiduciary duties by us against ETP and (iii) prejudgment interest in the amount of $66.4 million. The court also awarded post-judgment interest on such aggregate amount, to accrue at a rate of 5%, compounded annually.

We do not believe that the verdict or the judgment entered against us is supported by the evidence or the law. 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. We intend to vigorously oppose the judgment through the appeals process. As of December 31, 2015, we have not recorded a provision for this matter as management believes payment of damages in this case is not probable.

FTC Inquiry regarding Oiltanking Acquisition. On February 23, 2015, we received a Civil Investigative Demand and a related Subpoena *Duces Tecum* from the FTC requesting specified information relating to the Oiltanking acquisition and our operations. On April 13, 2015, we received a Civil Investigative Demand issued by the Attorney General of the State of Texas requesting copies of the same information and any correspondence with the FTC. We are in the process of complying with the requests and are cooperating with the investigations. Based on the limited information that we have at this time, we are unable to predict the outcome of the investigations.

Redelivery Commitments

We store natural gas, crude oil, NGLs and certain petrochemical products owned by third parties under various agreements. Under the terms of these agreements, we are generally required to redeliver volumes to the owner on demand. At December 31, 2015, we had approximately 10.2 trillion British thermal units ("TBtus") of natural gas, 18.7 MMBbls of crude oil, and 37.5 MMBbls of NGL and petrochemical products in our custody that were owned by third parties. We maintain insurance coverage related to such volumes that we believe is consistent with our exposure. See Note 18 for information regarding insurance matters.

Commitments Under Equity Compensation Plans of EPCO

In accordance with our agreements with EPCO, we reimburse EPCO for our share of its compensation expense associated with certain employees who perform management, administrative and operating functions for us. See Notes 13 and 15 for additional information regarding our accounting for equity-based awards and related party information, respectively.

Contractual Obligations

The following table summarizes our various contractual obligations at December 31, 2015. A description of each type of contractual obligation follows:

	Payment or Settlement due by Period						
Contractual Obligations	**Total**	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**
Scheduled maturities of debt obligations	$ 22,738.5	$ 1,864.1	$ 800.0	$ 1,100.0	$ 1,500.0	$ 1,500.0	$ 15,974.4
Estimated cash interest payments	$ 21,734.1	$ 1,053.0	$ 1,036.1	$ 975.6	$ 917.5	$ 859.7	$ 16,892.2
Operating lease obligations	$ 494.0	$ 64.2	$ 58.4	$ 50.3	$ 44.7	$ 41.0	$ 235.4
Purchase obligations:							
Product purchase commitments:							
Estimated payment obligations:							
Natural gas	$ 1,160.8	$ 451.3	$ 215.6	$ 215.6	$ 143.8	$ 73.5	$ 61.0
NGLs	$ 376.9	$ 319.3	$ 21.8	$ 23.9	$ 11.9	$ --	$ --
Crude oil	$ 441.5	$ 389.4	$ 17.9	$ 17.9	$ 16.3	$ --	$ --
Petrochemicals & refined products	$ 1,921.4	$ 1,868.6	$ 52.8	$ --	$ --	$ --	$ --
Other	$ 33.2	$ 8.7	$ 6.9	$ 4.1	$ 4.1	$ 2.7	$ 6.7
Underlying major volume commitments:							
Natural gas (in TBtus)	647	243	128	128	81	37	30
NGLs (in MMBbls)	39	30	3	4	2	--	--
Crude oil (in MMBbls)	14	11	1	1	1	--	--
Petrochemicals & refined products (in MMBbls)	146	126	20	--	--	--	--
Service payment commitments	$ 685.9	$ 184.5	$ 160.1	$ 91.8	$ 71.1	$ 43.7	$ 134.7
Capital expenditure commitments	$ 113.9	$ 113.9	$ --	$ --	$ --	$ --	$ --

Scheduled Maturities of Debt. We have long-term and short-term payment obligations under debt agreements. Amounts shown in the preceding table represent our scheduled future maturities of debt principal for the periods indicated. See Note 8 for additional information regarding our consolidated debt obligations.

Estimated Cash Interest Payments. Our estimated cash payments for interest are based on the principal amount of our consolidated debt obligations outstanding at December 31, 2015 and the contractually scheduled maturities of such balances. With respect to our variable-rate debt obligation, we applied the weighted-average interest rate paid during 2015 to determine the estimated cash payments. See Note 8 for the weighted-average variable interest rates charged in 2015. Our estimated cash payments for interest are significantly influenced by the long-term maturities of our $1.47 billion in junior subordinated notes. Our estimated cash payments for interest assume that these subordinated notes are not repaid prior to their respective maturity dates. We applied the current fixed interest rate through the respective maturity date for each junior subordinated note to determine the estimated cash payments for interest.

Operating Lease Obligations. We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the preceding table represent minimum cash lease payment obligations under our operating leases with terms in excess of one year.

Our significant lease agreements consist of (i) land held pursuant to right-of-way agreements and property leases, (ii) the lease of underground storage caverns for natural gas and NGLs, (iii) the lease of transportation equipment used in our operations, and (iv) leased office space with affiliates of EPCO. Currently, our significant lease agreements have terms that range from 5 to 30 years. The agreements for leased office space with affiliates of EPCO and underground NGL storage caverns we lease from a third party include renewal options that could extend these contracts for up to an additional 20 years. The remainder of our significant lease agreements do not provide for additional renewal terms.

Lease expense is charged to operating costs and expenses on a straight-line basis over the period of expected economic benefit. Contingent rental payments are expensed as incurred. We are generally required to perform routine maintenance on the underlying leased assets. In addition, certain leases give us the option to make leasehold improvements. Maintenance and repairs of leased assets resulting from our operations are charged to expense as incurred.

Consolidated costs and expenses include lease and rental expense amounts of $104.3 million, $94.2 million and $87.6 million during the years ended December 31, 2015, 2014 and 2013, respectively.

Purchase Obligations. We define purchase obligations as agreements to purchase goods or services that are enforceable and legally binding (i.e., unconditional) on us that specify all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We classify our unconditional purchase obligations into the following categories:

- We have long and short-term product purchase obligations for natural gas, NGLs, crude oil, petrochemicals and refined products with third party suppliers. The prices that we are obligated to pay under these contracts approximate market prices at the time we take delivery of the volumes. The preceding table shows our volume commitments and estimated payment obligations under these contracts for the periods presented. Our estimated future payment obligations are based on the contractual price in each agreement at December 31, 2015 applied to all future volume commitments. Actual future payment obligations may vary depending on prices at the time of delivery. At December 31, 2015, we did not have any significant product purchase commitments with fixed or minimum pricing provisions with remaining terms in excess of one year.

- We have long and short-term commitments to pay service providers. Our contractual service payment commitments primarily represent our obligations under firm pipeline transportation contracts. Payment obligations vary by contract, but generally represent a price per unit of volume multiplied by a firm transportation volume commitment.

- We have short-term payment obligations relating to our capital spending program, including our share of the capital spending of our unconsolidated affiliates. These commitments represent unconditional payment obligations for services to be rendered or products to be delivered in connection with capital projects.

Other Commitments

In connection with the agreements to acquire EFS Midstream (see Note 12), we are obligated to spend up to an aggregate of $270 million on specified midstream gathering assets for Pioneer and Reliance, if requested by these producers, over a ten-year period. If constructed, these new assets would be owned by us and be a component of the EFS Midstream asset network.

Other Long-Term Liabilities

The following table summarizes the components of "Other long-term liabilities" as presented on Consolidated Balance Sheets at the dates indicated:

	December 31,	
	2015	2014
Noncurrent portion of AROs (see Note 5)	$ 52.9	$ 83.2
Deferred revenues – non-current portion (see Note 3)	78.3	73.0
Liquidity Option Agreement (see Note 12)	245.1	219.7
Centennial guarantees	6.1	7.0
Other	29.1	28.2
Total	$ 411.5	$ 411.1

Liquidity Option Agreement

In connection with Step 1 of the Oiltanking acquisition (see Note 12), we entered into the Liquidity Option Agreement ("Liquidity Option") with OTA and M&B, whereby we granted M&B the option to sell to us 100% of the issued and outstanding capital stock of OTA at any time within a 90-day period commencing on February 1, 2020. At that time, OTA's only significant asset is expected to be the Enterprise common units it received in Step 1 of the Oiltanking acquisition, to the extent that such common units have not been sold by M&B prior to the option exercise date pursuant to the related Registration Rights Agreement (see Note 9) or otherwise. If M&B exercises the Liquidity Option, any assets or liabilities held by OTA at the time of exercise (e.g., any deferred tax liability), including any Enterprise common units held by OTA, will be indirectly acquired by us upon receipt of OTA's capital stock. The aggregate consideration to be paid by us for OTA's capital stock would equal 100% of the then-current fair market value of the Enterprise common units owned by OTA at the exercise date. The consideration paid may be in the form of newly issued Enterprise common units, cash or any mix thereof, as determined solely by us. We have the ability to issue the requisite number of common units needed to satisfy any potential obligation under the Liquidity Option.

If a Trigger Event occurs (as defined in the underlying agreements), the Liquidity Option may be exercised earlier within a 135-day period following notice of such event. Trigger Events include, among other scenarios, any "Enterprise Tax Event," which includes certain events in which OTA would recognize taxable gain on the Enterprise units that it owns.

If the Liquidity Option is exercised, we would indirectly acquire any Enterprise common units owned by OTA and assume all future income tax obligations of OTA associated with (i) owning common units encumbered by the entity-level taxes of a U.S. corporation and (ii) OTA's tax liabilities resulting from differences in the book and tax basis of such common units. We assigned a fair value of $219.7 million to the Liquidity Option at October 1, 2014 using an income approach, specifically a discounted cash flow analysis.

The fair value of the Liquidity Option, at any measurement date, represents the present value of estimated federal and state income tax payments that we believe a market participant would incur on the taxable income of OTA. We expect that OTA's taxable income would, in turn, be based on an allocation of our partnership's taxable income to the common units held by OTA and reflect any tax mitigation strategies we believe could be employed. Our valuation estimate for the Liquidity Option is based on significant inputs that are not observable in the market (i.e., Level 3 inputs). For example, the fair value of the Liquidity Option at December 31, 2015 was estimated at $245.1 million and was based on the following Level 3 inputs:

- OTA remains in existence (i.e., is not dissolved and its assets sold) between one and 30 years following exercise of the Liquidity Option, depending on the liquidity preference of its owner. An equal probability was assigned to each year in the 30-year forecast period;

- Forecast annual growth rates of Enterprise's taxable earnings before interest, taxes, depreciation and amortization ranging from 2% to 15%;

- OTA's ownership interest in Enterprise common units is assumed to be diluted over time in connection with Enterprise's issuance of equity for general company reasons. For purposes of the valuation at December 31, 2015, we used ownership interests ranging from 1.9% to 2.7%;

- OTA assumes approximately $2.2 billion of existing long-term debt (30-year maturity) immediately after the Liquidity Option is exercised. For purposes of the valuation at December 31, 2015, we used a market rate commensurate with level of debt and tenure of approximately 6.4%;

- A forecasted yield on Enterprise common units of 5.8% to 6.6%;

- OTA pays an aggregate federal and state income tax rate of 38% on its taxable income; and

- A discount rate of 7.5% based on our weighted-average cost of capital at December 31, 2015.

Furthermore, our valuation estimate incorporates probability-weighted scenarios reflecting the likelihood that M&B may elect to divest a portion of the Enterprise common units held by OTA prior to exercise of the option. Based on these scenarios, we expect that OTA would own approximately 78.9% of the 54,807,352 Enterprise common units it received on October 1, 2014 when the option period begins in February 2020.

Changes in the fair value of the Liquidity Option are recognized in earnings as a component of other income (expense) on our Statements of Consolidated Operations. Results for the year ended December 31, 2015 include $25.4 million of aggregate non-cash expense attributable to accretion and changes in management estimates regarding inputs to the valuation model. The carrying value of the Liquidity Option Agreement, which is a component of "Other long-term liabilities" on our Consolidated Balance Sheet, increased to $245.1 million at December 31, 2015 as of a result of these changes.

The estimated liability for the Liquidity Option at October 1, 2014 reflects a $100.3 million retrospective adjustment made in the third quarter of 2015 upon finalization of the purchase price allocation for the Oiltanking acquisition. The retrospective adjustment was applied in our December 31, 2014 Consolidated Balance Sheet as an increase in goodwill and a corresponding increase in the Liquidity Option Agreement liability, which is a component of "Other long-term liabilities." The retrospective adjustment did not impact our historical results of operations, cash flows or other balance sheet amounts.

If M&B exercises the Liquidity Option, any assets or liabilities held by OTA at the time of exercise (e.g., any deferred tax liability), including any Enterprise common units held by OTA, will be indirectly acquired by us upon receipt of OTA's capital stock. To the extent that OTA's deferred tax liability exceeds the then current book value of the Liquidity Option liability, we will recognize expense for the difference.

Centennial Guarantees

At December 31, 2015, Centennial's debt obligations consisted of $67.2 million borrowed under a master shelf loan agreement. Borrowings under the master shelf agreement mature in May 2024 and are collateralized by substantially all of Centennial's assets and severally guaranteed 50% by us and 50% by our joint venture partner in Centennial. If Centennial were to default on its debt obligations, we and our joint venture partner would each be required to make an approximate $33.6 million payment to Centennial's lenders in connection with the guarantee agreements (based on Centennial's debt principal outstanding at December 31, 2015). We recognized a liability of $4.9 million for our share of the Centennial debt guaranty at December 31, 2015.

In lieu of Centennial procuring insurance to satisfy third party claims arising from a catastrophic event, we and Centennial's other joint venture partner have entered a limited cash call agreement. We are obligated to contribute up to a maximum of $50.0 million in the event of a catastrophic event. At December 31, 2015, we have a recorded liability of $2.1 million representing the estimated fair value of our cash call guaranty. Our cash contributions to Centennial under the agreement may be covered by our other insurance policies depending on the nature of the catastrophic event.

Note 18. Significant Risks and Uncertainties

Nature of Operations

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.

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 crude 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.

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.

Credit Risk

We may incur credit risk to the extent counterparties do not fulfill their obligations to us in connection with our marketing of natural gas, NGLs, petrochemicals, refined products and crude oil 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, such as those experienced throughout 2015 and that we continue to experience at the beginning of 2016, increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings or small-scale companies. We manage our exposure to credit risk through credit analysis, credit approvals, credit limits and monitoring procedures, and for certain transactions may utilize letters of credit, prepayments, net out agreements and guarantees. However, these procedures and policies do not fully eliminate customer credit risk.

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

In those situations where we are exposed to credit risk in our derivative instrument transactions, we analyze the counterparty's financial condition prior to entering into an agreement, establish credit and/or margin limits and monitor the appropriateness of these limits on an ongoing basis. Generally, we do not require collateral for such transactions nor do we currently anticipate nonperformance by our material counterparties.

Insurance Matters

We participate as a named insured in EPCO's insurance program, which provides us with property damage, business interruption and other insurance coverage, the scope and amounts of which we believe are customary and prudent for the nature and extent of our operations. While we believe EPCO maintains adequate insurance coverage on our behalf, insurance may not fully cover every type of damage, interruption or other loss that might occur. If we were to incur a significant loss for which we were not fully insured, it could have a material impact on our financial position, results of operations and cash flows.

In addition, there may be timing differences between amounts we accrue related to property damage expense, amounts we are required to pay in connection with a loss, and amounts we subsequently receive from insurance carriers as reimbursements. Any event that materially interrupts the revenues generated by our consolidated operations, or other losses that require us to make material expenditures not reimbursed by insurance, could reduce our ability to pay distributions to our unitholders and, accordingly, adversely affect the market price of our common units.

Involuntary conversions result from the loss of an asset due to some unforeseen event (e.g., destruction due to a fire). Some of these events are covered by insurance, thus resulting in a property damage insurance recovery. Amounts we receive from insurance carriers are net of any deductibles related to the covered event. We record a receivable from insurance to the extent we recognize a loss from an involuntary conversion event and the likelihood of our recovering such loss is deemed probable. To the extent that any of our insurance claim receivables are later judged not probable of recovery (e.g., due to new information), such amounts are expensed. We recognize gains on involuntary conversions when the amount received from insurance exceeds the net book value of the retired assets.

In addition, we do not recognize gains related to insurance recoveries until all contingencies related to such proceeds have been resolved, that is, a non-refundable cash payment is received from the insurance carrier or we have a binding settlement agreement with the carrier that clearly states that a non-refundable payment will be made. To the extent that an asset is rebuilt, the associated expenditures are capitalized, as appropriate, on our Consolidated Balance Sheets and presented as "Capital expenditures" on our Statements of Consolidated Cash Flows.

Under our current insurance program, the standalone deductible for property damage claims is $55 million. We also have business interruption protection; however, such claims must involve physical damage and have a combined loss value in excess of $55 million and the period of interruption must exceed 60 days.

We received $95.0 million and $15.0 million of nonrefundable insurance proceeds during the years ended December 31, 2014 and 2013, respectively, attributable to property damage claims we filed in connection with a February 2011 NGL release and fire at the West Storage location of our Mont Belvieu, Texas underground storage facility. Operating income for the years ended December 31, 2014 and 2013 includes $95.0 million and $15.0 million of gains, respectively, related to these insurance recoveries. The amounts we received during the first quarter of 2014 represent the final payments on this property damage claim.

Note 19. Supplemental Cash Flow Information

The following table provides information regarding the net effect of changes in our operating accounts and cash payments for interest and income taxes for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Decrease (increase) in:			
Accounts receivable – trade	$ 1,279.3	$ 1,685.4	$ (1,136.2)
Accounts receivable – related parties	1.3	3.8	(3.6)
Inventories	(72.7)	(105.6)	38.6
Prepaid and other current assets	(59.1)	(74.6)	(6.3)
Other assets	(5.8)	18.7	2.4
Increase (decrease) in:			
Accounts payable – trade	(52.9)	(141.0)	(10.1)
Accounts payable – related parties	(34.8)	(31.6)	23.6
Accrued product payables	(1,342.4)	(1,647.8)	1,043.8
Accrued interest	16.5	31.3	3.5
Other current liabilities	(67.1)	141.3	(35.1)
Other liabilities	14.4	11.9	(18.2)
Net effect of changes in operating accounts	$ (323.3)	$ (108.2)	$ (97.6)
Cash payments for interest, net of $149.1, $77.9 and $133.0 capitalized in 2015, 2014 and 2013, respectively	$ 911.6	$ 832.1	$ 781.5
Cash payments for federal and state income taxes	$ 17.5	$ 16.1	$ 35.0

We incurred liabilities for construction in progress that had not been paid at December 31, 2015, 2014 and 2013 of $472.8 million, $372.8 million and $205.3 million, respectively. Such amounts are not included under the caption "Capital expenditures" on the Statements of Consolidated Cash Flows.

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with projects related to pipeline construction activities and production well tie-ins. These cash receipts are presented as "Contributions in aid of construction costs" within the investing activities section of our Statements of Consolidated Cash Flows.

In addition, we incurred a $1.0 billion payable in connection with our acquisition of EFS Midstream in July 2015 that will be paid no later than the first anniversary of the closing date of the acquisition (see Note 12).

The following table presents our cash proceeds from asset sales and insurance recoveries for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Sale of Offshore Business (see Note 5)	$ 1,527.7	$ --	$ --
Insurance recoveries attributable to West Storage claims (see Note 18)	--	95.0	15.0
Cash proceeds from other asset sales	80.9	50.3	265.6
Total	$ 1,608.6	$ 145.3	$ 280.6

The following table presents net gains (losses) attributable to asset sales and insurance recoveries for the periods indicated:

	For the Year Ended December 31,		
	2015	2014	2013
Sale of Offshore Business	$ (12.3)	$ --	$ --
Gains attributable to West Storage insurance recoveries (see Note 18)	--	95.0	15.0
Net gains (losses) attributable to other asset sales	(3.3)	7.1	68.3
Total	$ (15.6)	$ 102.1	$ 83.3

See Note 12 for information regarding non-cash consideration we issued in connection with the Oiltanking acquisition.

Note 20. Quarterly Financial Information (Unaudited)

The following table presents selected quarterly financial data for the periods indicated:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
For the Year Ended December 31, 2015:				
Revenues	$ 7,472.5	$ 7,092.5	$ 6,307.9	$ 6,155.0
Operating income	896.0	800.3	909.4	934.5
Net income	650.6	556.6	657.7	693.5
Net income attributable to limited partners	636.1	551.0	649.3	684.8
Earnings per unit:				
Basic	$ 0.33	$ 0.28	$ 0.33	$ 0.34
Diluted	$ 0.32	$ 0.28	$ 0.32	$ 0.34
For the Year Ended December 31, 2014:				
Revenues	$ 12,909.9	$ 12,520.8	$ 12,330.2	$ 10,190.3
Operating income	1,032.7	884.3	937.7	921.0
Net income	806.7	646.5	699.2	681.1
Net income attributable to limited partners	798.8	637.7	691.1	659.8
Earnings per unit:				
Basic	$ 0.44	$ 0.35	$ 0.38	$ 0.35
Diluted	$ 0.43	$ 0.34	$ 0.37	$ 0.34

The sum of our quarterly earnings per unit amounts may not equal our full year amounts due to slight rounding differences.

Note 21. Condensed Consolidating Financial Information

EPO conducts all of our business. Currently, we have no independent operations and no material assets outside those of EPO.

EPO has issued publicly traded debt securities. As the parent company of EPO, Enterprise Products Partners L.P. guarantees substantially all of the debt obligations of EPO. 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. See Note 8 for additional information regarding our consolidated debt obligations.

EPO's consolidated subsidiaries have no significant restrictions on their ability to pay distributions or make loans to Enterprise Products Partners L.P.

Enterprise Products Partners L.P.
Condensed Consolidating Balance Sheet
December 31, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 14.4	$ 71.1	$ (50.6)	$ 34.9	$ --	$ --	$ 34.9
Accounts receivable – trade, net	811.3	1,755.8	2.8	2,569.9	--	--	2,569.9
Accounts receivable – related parties	59.0	795.4	(853.0)	1.4	--	(0.2)	1.2
Inventories	786.9	251.4	(0.2)	1,038.1	--	--	1,038.1
Derivative assets	150.4	108.2	--	258.6	--	--	258.6
Prepaid and other current assets	168.3	249.1	(7.1)	410.3	--	--	410.3
Total current assets	1,990.3	3,231.0	(908.1)	4,313.2	--	(0.2)	4,313.0
Property, plant and equipment, net	3,859.8	28,173.5	1.4	32,034.7	--	--	32,034.7
Investments in unconsolidated affiliates	38,655.0	4,067.3	(40,093.8)	2,628.5	20,540.2	(20,540.2)	2,628.5
Intangible assets, net	721.2	3,330.7	(14.7)	4,037.2	--	--	4,037.2
Goodwill	459.5	5,285.7	--	5,745.2	--	--	5,745.2
Other assets	280.2	47.9	(135.2)	192.9	0.5	--	193.4
Total assets	$ 45,966.0	$ 44,136.1	$ (41,150.4)	$ 48,951.7	$ 20,540.7	$ (20,540.4)	$ 48,952.0
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 1,863.8	$ 0.1	$ --	$ 1,863.9	$ --	$ --	$ 1,863.9
Accounts payable – trade	375.3	535.1	(50.6)	859.8	0.3	--	860.1
Accounts payable – related parties	885.3	62.3	(863.5)	84.1	0.2	(0.2)	84.1
Accrued product payables	997.7	1,489.3	(2.6)	2,484.4	--	--	2,484.4
Accrued liability related to EFS Midstream acquisition	--	993.2	--	993.2	--	--	993.2
Accrued interest	352.0	0.1	--	352.1	--	--	352.1
Other current liabilities	178.7	357.1	(7.0)	528.8	--	--	528.8
Total current liabilities	4,652.8	3,437.2	(923.7)	7,166.3	0.5	(0.2)	7,166.6
Long-term debt	20,811.4	15.3	--	20,826.7	--	--	20,826.7
Deferred tax liabilities	3.4	40.8	(0.8)	43.4	--	2.7	46.1
Other long-term liabilities	14.5	286.9	(135.0)	166.4	245.1	--	411.5
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	20,483.9	40,297.2	(40,266.8)	20,514.3	20,295.1	(20,514.3)	20,295.1
Noncontrolling interests	--	58.7	175.9	234.6	--	(28.6)	206.0
Total equity	20,483.9	40,355.9	(40,090.9)	20,748.9	20,295.1	(20,542.9)	20,501.1
Total liabilities and equity	$ 45,966.0	$ 44,136.1	$ (41,150.4)	$ 48,951.7	$ 20,540.7	$ (20,540.4)	$ 48,952.0

Enterprise Products Partners L.P.
Condensed Consolidating Balance Sheet
December 31, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
ASSETS							
Current assets:							
Cash and cash equivalents and restricted cash	$ 18.7	$ 70.4	$ (14.7)	$ 74.4	$ --	$ --	$ 74.4
Accounts receivable – trade, net	1,128.5	2,698.2	(3.7)	3,823.0	--	--	3,823.0
Accounts receivable – related parties	158.8	1,114.6	(1,266.6)	6.8	--	(4.0)	2.8
Inventories	831.8	182.8	(0.4)	1,014.2	--	--	1,014.2
Derivative assets	102.0	124.0	--	226.0	--	--	226.0
Prepaid and other current assets	435.7	222.3	(308.5)	349.5	--	0.8	350.3
Total current assets	2,675.5	4,412.3	(1,593.9)	5,493.9	--	(3.2)	5,490.7
Property, plant and equipment, net	2,871.7	26,912.0	97.9	29,881.6	--	--	29,881.6
Investments in unconsolidated affiliates	36,937.5	3,556.4	(37,451.9)	3,042.0	18,287.5	(18,287.5)	3,042.0
Intangible assets, net	2,527.3	1,292.4	482.4	4,302.1	--	--	4,302.1
Goodwill	1,956.1	1,721.4	622.7	4,300.2	--	--	4,300.2
Other assets	139.3	45.8	(0.7)	184.4	--	--	184.4
Total assets	$ 47,107.4	$ 37,940.3	$ (37,843.5)	$ 47,204.2	$ 18,287.5	$ (18,290.7)	$ 47,201.0
LIABILITIES AND EQUITY							
Current liabilities:							
Current maturities of debt	$ 2,206.4	$ --	$ --	$ 2,206.4	$ --	$ --	$ 2,206.4
Accounts payable – trade	216.6	571.4	(14.8)	773.2	0.6	--	773.8
Accounts payable – related parties	1,226.5	173.3	(1,280.9)	118.9	4.0	(4.0)	118.9
Accrued product payables	1,570.0	2,287.9	(4.6)	3,853.3	--	--	3,853.3
Accrued interest	335.4	0.7	(0.6)	335.5	--	--	335.5
Other current liabilities	130.8	763.7	(308.7)	585.8	--	--	585.8
Total current liabilities	5,685.7	3,797.0	(1,609.6)	7,873.1	4.6	(4.0)	7,873.7
Long-term debt	19,142.5	14.9	--	19,157.4	--	--	19,157.4
Deferred tax liabilities	4.9	58.5	(0.9)	62.5	--	4.1	66.6
Other long-term liabilities	10.9	180.8	(0.3)	191.4	219.7	--	411.1
Commitments and contingencies							
Equity:							
Partners' and other owners' equity	22,263.4	33,820.9	(37,820.6)	18,263.7	18,063.2	(18,263.7)	18,063.2
Noncontrolling interests	--	68.2	1,587.9	1,656.1	--	(27.1)	1,629.0
Total equity	22,263.4	33,889.1	(36,232.7)	19,919.8	18,063.2	(18,290.8)	19,692.2
Total liabilities and equity	$ 47,107.4	$ 37,940.3	$ (37,843.5)	$ 47,204.2	$ 18,287.5	$ (18,290.7)	$ 47,201.0

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 20,104.8	$ 19,087.0	$ (12,163.9)	$ 27,027.9	$ --	$ --	$ 27,027.9
Costs and expenses:							
Operating costs and expenses	19,283.7	16,549.3	(12,164.3)	23,668.7	--	--	23,668.7
General and administrative costs	38.2	152.3	--	190.5	2.1	--	192.6
Total costs and expenses	19,321.9	16,701.6	(12,164.3)	23,859.2	2.1	--	23,861.3
Equity in income of unconsolidated affiliates	2,718.4	417.5	(2,762.3)	373.6	2,548.7	(2,548.7)	373.6
Operating income	3,501.3	2,802.9	(2,761.9)	3,542.3	2,546.6	(2,548.7)	3,540.2
Other income (expense):							
Interest expense	(952.9)	(12.0)	3.1	(961.8)	--	--	(961.8)
Other, net	5.2	0.8	(3.1)	2.9	(25.4)	--	(22.5)
Total other expense, net	(947.7)	(11.2)	--	(958.9)	(25.4)	--	(984.3)
Income before income taxes	2,553.6	2,791.7	(2,761.9)	2,583.4	2,521.2	(2,548.7)	2,555.9
Benefit from (provision for) income taxes	(8.7)	12.7	--	4.0	--	(1.5)	2.5
Net income	2,544.9	2,804.4	(2,761.9)	2,587.4	2,521.2	(2,550.2)	2,558.4
Net loss (income) attributable to noncontrolling interests	--	0.9	(42.9)	(42.0)	--	4.8	(37.2)
Net income attributable to entity	$ 2,544.9	$ 2,805.3	$ (2,804.8)	$ 2,545.4	$ 2,521.2	$ (2,545.4)	$ 2,521.2

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 32,468.5	$ 32,488.2	$ (17,005.5)	$ 47,951.2	$ --	$ --	$ 47,951.2
Costs and expenses:							
Operating costs and expenses	31,579.2	29,647.6	(17,006.3)	44,220.5	--	--	44,220.5
General and administrative costs	39.1	173.2	--	212.3	2.2	--	214.5
Total costs and expenses	31,618.3	29,820.8	(17,006.3)	44,432.8	2.2	--	44,435.0
Equity in income of unconsolidated affiliates	2,865.2	354.3	(2,960.0)	259.5	2,789.6	(2,789.6)	259.5
Operating income	3,715.4	3,021.7	(2,959.2)	3,777.9	2,787.4	(2,789.6)	3,775.7
Other income (expense):							
Interest expense	(921.3)	(2.5)	2.8	(921.0)	--	--	(921.0)
Other, net	3.4	1.3	(2.8)	1.9	--	--	1.9
Total other expense, net	(917.9)	(1.2)	--	(919.1)	--	--	(919.1)
Income before income taxes	2,797.5	3,020.5	(2,959.2)	2,858.8	2,787.4	(2,789.6)	2,856.6
Provision for income taxes	(11.5)	(9.8)	0.2	(21.1)	--	(2.0)	(23.1)
Net income	2,786.0	3,010.7	(2,959.0)	2,837.7	2,787.4	(2,791.6)	2,833.5
Net loss (income) attributable to noncontrolling interests	--	0.4	(51.5)	(51.1)	--	5.0	(46.1)
Net income attributable to entity	$ 2,786.0	$ 3,011.1	$ (3,010.5)	$ 2,786.6	$ 2,787.4	$ (2,786.6)	$ 2,787.4

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Revenues	$ 30,007.4	$ 31,641.3	$ (13,921.7)	$ 47,727.0	$ --	$ --	$ 47,727.0
Costs and expenses:							
Operating costs and expenses	29,176.7	28,983.7	(13,921.7)	44,238.7	--	--	44,238.7
General and administrative costs	29.1	157.0	--	186.1	2.2	--	188.3
Total costs and expenses	29,205.8	29,140.7	(13,921.7)	44,424.8	2.2	--	44,427.0
Equity in income of unconsolidated affiliates	2,609.0	204.8	(2,646.5)	167.3	2,599.1	(2,599.1)	167.3
Operating income	3,410.6	2,705.4	(2,646.5)	3,469.5	2,596.9	(2,599.1)	3,467.3
Other income (expense):							
Interest expense	(800.8)	(1.7)	--	(802.5)	--	--	(802.5)
Other, net	0.3	(0.5)	--	(0.2)	--	--	(0.2)
Total other expense, net	(800.5)	(2.2)	--	(802.7)	--	--	(802.7)
Income before income taxes	2,610.1	2,703.2	(2,646.5)	2,666.8	2,596.9	(2,599.1)	2,664.6
Provision for income taxes	(13.9)	(42.6)	--	(56.5)	--	(1.0)	(57.5)
Net income	2,596.2	2,660.6	(2,646.5)	2,610.3	2,596.9	(2,600.1)	2,607.1
Net loss (income) attributable to noncontrolling interests	--	(1.2)	(12.9)	(14.1)	--	3.9	(10.2)
Net income attributable to entity	$ 2,596.2	$ 2,659.4	$ (2,659.4)	$ 2,596.2	$ 2,596.9	$ (2,596.2)	$ 2,596.9

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended December 31, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 2,578.6	$ 2,793.1	$ (2,761.9)	$ 2,609.8	$ 2,543.6	$ (2,572.6)	$ 2,580.8
Comprehensive loss (income) attributable to noncontrolling interests	--	0.9	(42.9)	(42.0)	--	4.8	(37.2)
Comprehensive income attributable to entity	$ 2,578.6	$ 2,794.0	$ (2,804.8)	$ 2,567.8	$ 2,543.6	$ (2,567.8)	$ 2,543.6

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended December 31, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 2,856.4	$ 3,057.6	$ (2,958.9)	$ 2,955.1	$ 2,904.8	$ (2,909.0)	$ 2,950.9
Comprehensive loss (income) attributable to noncontrolling interests	--	0.4	(51.5)	(51.1)	--	5.0	(46.1)
Comprehensive income attributable to entity	$ 2,856.4	$ 3,058.0	$ (3,010.4)	$ 2,904.0	$ 2,904.8	$ (2,904.0)	$ 2,904.8

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Comprehensive Income
For the Year Ended December 31, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Comprehensive income	$ 2,616.5	$ 2,651.6	$ (2,646.5)	$ 2,621.6	$ 2,608.3	$ (2,611.4)	$ 2,618.5
Comprehensive income attributable to noncontrolling interests	--	(1.2)	(12.9)	(14.1)	--	3.9	(10.2)
Comprehensive income attributable to entity	$ 2,616.5	$ 2,650.4	$ (2,659.4)	$ 2,607.5	$ 2,608.3	$ (2,607.5)	$ 2,608.3

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2015

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 2,544.9	$ 2,804.4	$ (2,761.9)	$ 2,587.4	$ 2,521.2	$ (2,550.2)	$ 2,558.4
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	144.9	1,371.5	(0.4)	1,516.0	--	--	1,516.0
Equity in income of unconsolidated affiliates	(2,718.4)	(417.5)	2,762.3	(373.6)	(2,548.7)	2,548.7	(373.6)
Distributions received from unconsolidated affiliates	1,989.6	307.7	(1,835.2)	462.1	3,000.2	(3,000.2)	462.1
Net effect of changes in operating accounts and other operating activities	882.8	(1,031.0)	(35.9)	(184.1)	22.1	1.5	(160.5)
Net cash flows provided by operating activities	2,843.8	3,035.1	(1,871.1)	4,007.8	2,994.8	(3,000.2)	4,002.4
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(1,180.0)	(2,631.6)	--	(3,811.6)	--	--	(3,811.6)
Cash used for business combinations, net of cash received	(1,069.9)	13.4	--	(1,056.5)	--	--	(1,056.5)
Proceeds from asset sales and insurance recoveries	1,531.3	77.3	--	1,608.6	--	--	1,608.6
Other investing activities	(1,513.4)	(1,248.2)	2,579.3	(182.3)	(1,179.8)	1,179.8	(182.3)
Cash used in investing activities	(2,232.0)	(3,789.1)	2,579.3	(3,441.8)	(1,179.8)	1,179.8	(3,441.8)
Financing activities:							
Borrowings under debt agreements	21,081.1	133.9	(133.9)	21,081.1	--	--	21,081.1
Repayments of debt	(19,867.2)	--	--	(19,867.2)	--	--	(19,867.2)
Cash distributions paid to partners	(3,000.2)	(1,882.4)	1,882.4	(3,000.2)	(2,943.7)	3,000.2	(2,943.7)
Cash payments made in connection with DERs	--	--	--	--	(7.7)	--	(7.7)
Cash distributions paid to noncontrolling interests	--	(0.8)	(47.2)	(48.0)	--	--	(48.0)
Cash contributions from noncontrolling interests	--	54.4	(0.4)	54.0	--	--	54.0
Net cash proceeds from issuance of common units	--	--	--	--	1,188.6	--	1,188.6
Cash contributions from owners	1,179.8	2,445.0	(2,445.0)	1,179.8	--	(1,179.8)	--
Other financing activities	(24.0)	3.1	--	(20.9)	(52.2)	--	(73.1)
Cash provided by (used in) financing activities	(630.5)	753.2	(744.1)	(621.4)	(1,815.0)	1,820.4	(616.0)
Net change in cash and cash equivalents	(18.7)	(0.8)	(35.9)	(55.4)	--	--	(55.4)
Cash and cash equivalents, January 1	18.7	70.4	(14.7)	74.4	--	--	74.4
Cash and cash equivalents, December 31	$ --	$ 69.6	$ (50.6)	$ 19.0	$ --	$ --	$ 19.0

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2014

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 2,786.0	$ 3,010.7	$ (2,959.0)	$ 2,837.7	$ 2,787.4	$ (2,791.6)	$ 2,833.5
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	153.0	1,208.0	(0.5)	1,360.5	--	--	1,360.5
Equity in income of unconsolidated affiliates	(2,865.2)	(354.3)	2,960.0	(259.5)	(2,789.6)	2,789.6	(259.5)
Distributions received from unconsolidated affiliates	4,539.9	327.1	(4,491.9)	375.1	2,702.9	(2,702.9)	375.1
Net effect of changes in operating accounts and other operating activities	(627.0)	479.4	5.7	(141.9)	(7.5)	2.0	(147.4)
Net cash flows provided by operating activities	3,986.7	4,670.9	(4,485.7)	4,171.9	2,693.2	(2,702.9)	4,162.2
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(647.9)	(2,216.1)	--	(2,864.0)	--	--	(2,864.0)
Cash used for business combinations, net of cash received	(2,437.5)	20.7	--	(2,416.8)	--	--	(2,416.8)
Proceeds from asset sales and insurance recoveries	4.3	141.0	--	145.3	--	--	145.3
Other investing activities	(2,603.4)	(660.0)	2,601.0	(662.4)	(384.6)	384.6	(662.4)
Cash used in investing activities	(5,684.5)	(2,714.4)	2,601.0	(5,797.9)	(384.6)	384.6	(5,797.9)
Financing activities:							
Borrowings under debt agreements	18,361.1	--	--	18,361.1	--	--	18,361.1
Repayments of debt	(14,341.1)	--	--	(14,341.1)	--	--	(14,341.1)
Cash distributions paid to partners	(2,702.9)	(4,537.8)	4,537.8	(2,702.9)	(2,638.1)	2,702.9	(2,638.1)
Cash payments made in connection with DERs	--	--	--	--	(3.7)	--	(3.7)
Cash distributions paid to noncontrolling interests	--	(2.7)	(45.9)	(48.6)	--	--	(48.6)
Cash contributions from noncontrolling interests	--	--	4.0	4.0	--	--	4.0
Net cash proceeds from issuance of common units	--	--	--	--	388.8	--	388.8
Cash contributions from owners	384.6	2,604.9	(2,604.9)	384.6	--	(384.6)	--
Other financing activities	(13.6)	--	--	(13.6)	(55.6)	--	(69.2)
Cash provided by (used in) financing activities	1,688.1	(1,935.6)	1,891.0	1,643.5	(2,308.6)	2,318.3	1,653.2
Net change in cash and cash equivalents	(9.7)	20.9	6.3	17.5	--	--	17.5
Cash and cash equivalents, January 1	28.4	49.5	(21.0)	56.9	--	--	56.9
Cash and cash equivalents, December 31	$ 18.7	$ 70.4	$ (14.7)	$ 74.4	$ --	$ --	$ 74.4

Enterprise Products Partners L.P.
Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2013

	EPO and Subsidiaries						
	Subsidiary Issuer (EPO)	Other Subsidiaries (Non-guarantor)	EPO and Subsidiaries Eliminations and Adjustments	Consolidated EPO and Subsidiaries	Enterprise Products Partners L.P. (Guarantor)	Eliminations and Adjustments	Consolidated Total
Operating activities:							
Net income	$ 2,596.2	$ 2,660.6	$ (2,646.5)	$ 2,610.3	$ 2,596.9	$ (2,600.1)	$ 2,607.1
Reconciliation of net income to net cash flows provided by operating activities:							
Depreciation, amortization and accretion	143.5	1,072.8	1.3	1,217.6	--	--	1,217.6
Equity in income of unconsolidated affiliates	(2,609.0)	(204.8)	2,646.5	(167.3)	(2,599.1)	2,599.1	(167.3)
Distributions received from unconsolidated affiliates	4,523.2	233.7	(4,505.3)	251.6	2,454.4	(2,454.4)	251.6
Net effect of changes in operating accounts and other operating activities	(1,351.0)	1,323.4	(10.1)	(37.7)	(7.8)	2.0	(43.5)
Net cash flows provided by operating activities	3,302.9	5,085.7	(4,514.1)	3,874.5	2,444.4	(2,453.4)	3,865.5
Investing activities:							
Capital expenditures, net of contributions in aid of construction costs	(517.8)	(2,864.4)	--	(3,382.2)	--	--	(3,382.2)
Proceeds from asset sales and insurance recoveries	59.6	221.0	--	280.6	--	--	280.6
Other investing activities	(3,163.6)	(769.5)	2,777.2	(1,155.9)	(1,791.1)	1,791.1	(1,155.9)
Cash used in investing activities	(3,621.8)	(3,412.9)	2,777.2	(4,257.5)	(1,791.1)	1,791.1	(4,257.5)
Financing activities:							
Borrowings under debt agreements	13,852.8	--	--	13,852.8	--	--	13,852.8
Repayments of debt	(12,650.8)	(29.8)	--	(12,680.6)	--	--	(12,680.6)
Cash distributions paid to partners	(2,453.4)	(4,514.1)	4,514.1	(2,453.4)	(2,400.4)	2,453.5	(2,400.3)
Cash distributions paid to noncontrolling interests	--	--	(8.9)	(8.9)	--	--	(8.9)
Cash contributions from noncontrolling interests	--	--	115.4	115.4	--	--	115.4
Net cash proceeds from issuance of common units	--	--	--	--	1,792.0	--	1,792.0
Cash contributions from owners	1,791.2	2,892.6	(2,892.6)	1,791.2	--	(1,791.2)	--
Other financing activities	(192.5)	--	--	(192.5)	(45.1)	--	(237.6)
Cash provided by (used in) financing activities	347.3	(1,651.3)	1,728.0	424.0	(653.5)	662.3	432.8
Net change in cash and cash equivalents	28.4	21.5	(8.9)	41.0	(0.2)	--	40.8
Cash and cash equivalents, January 1	--	28.0	(12.1)	15.9	0.2	--	16.1
Cash and cash equivalents, December 31	$ 28.4	$ 49.5	$ (21.0)	$ 56.9	$ --	$ --	$ 56.9