NGL Energy Partners LP
Form 10-K
May 31, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K
(Mark One)
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended March 31, 2016
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________
Commission File Number: 001-35172
NGL Energy Partners LP
(Exact Name of Registrant as Specified in Its Charter)

Delaware	27-3427920
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
6120 South Yale Avenue	
Suite 805	74136
Tulsa, Oklahoma	
(Address of Principal Executive Offices)	(Zip code)

(918) 481-1119
(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 Representing Limited Partner Interests	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 ý No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý
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 ý No o
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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting

company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value at September 30, 2015 of the Common Units held by non-affiliates of the registrant, based on the reported closing price of the Common Units on the New York Stock Exchange on such date ($19.97 per Common Unit) was $1.9 billion. For purposes of this computation, all executive officers, directors and 10% owners of the registrant are deemed to be affiliates. Such a determination should not be deemed an admission that such executive officers, directors and 10% beneficial owners are affiliates.

At May 23, 2016, there were 104,169,573 common units issued and outstanding.

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EXPLANATORY NOTE

This Annual Report on Form 10-K of NGL Energy Partners LP (referred to herein as the "Partnership," "we," "us" or "our") includes restated unaudited quarterly consolidated financial information as of and for the periods ended June 30, 2015, September 30, 2015 and December 31, 2015. We will not file amended periodic reports for any prior filings, including Forms 10-Q for any of the affected quarterly periods.

Restatement Background

In connection with the recording of business combinations that occurred in the fourth quarter of fiscal year 2016, the Partnership identified certain contingent consideration liabilities in connection with those fourth quarter 2016 business combinations, and determined that the Partnership had not correctly accounted for contingent consideration related to royalty payments that were part of certain prior business combinations within its Water Solutions segment that had occurred prior to the fourth quarter of fiscal year 2016. The application of the correct accounting treatment results in an increase to goodwill, current liabilities and long-term liabilities and an increase to earnings for the first three quarters of the fiscal year ended March 31, 2016.

As a result of this error, on May 31, 2016, the Partnership's management, Audit Committee and Board of Directors concluded, after consideration of the relevant facts and circumstances, that the Partnership's unaudited interim consolidated financial statements set forth in the Partnership's Quarterly Reports on Form 10-Q for the quarters ended June 30, 2015, September 30, 2015 and December 31, 2015 should be restated and that such financial statements previously filed with the Securities and Exchange Commission (the "SEC") should no longer be relied upon and on that date filed a Form 8-K with the SEC to report such non-reliance. In addition, based on the relevant facts and circumstances, the Partnership's management, Audit Committee and Board of Directors concluded that the correction was not material to any other periods prior to fiscal year 2016.

Within this Annual Report on Form 10-K for the year ended March 31, 2016, the Partnership has included restated unaudited quarterly data for each of the quarters ended June 30, 2015, September 30, 2015 and December 31, 2015 in the notes to the consolidated financial statements. For the financial data related to its fiscal year ended March 31, 2015 and all unaudited quarterly financial data for the quarters ended June 30, 2014, September 30, 2014, December 31, 2014 and March 31, 2015, the Partnership has included financial data that contains immaterial corrections for this issue.

Management has evaluated the effect of the restatements on its prior conclusions regarding the effectiveness of the Partnership's internal control over financial reporting and disclosure controls and procedures and has concluded that a material weakness existed during each of the periods requiring correction. In connection therewith, the Partnership's management concluded that during the periods requiring correction, the Partnership did not maintain effective controls over the identification of assets acquired and liabilities assumed in the Partnership's business combinations. Accordingly, the Partnership's internal control over financial reporting and disclosure controls and procedures were not effective during the periods being corrected.

The following parts of this Form 10-K include discussion of or disclosure related to the restatement:
- Part I, Item 1A - Risk Factors
- Part II, Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations
- Part II, Item 8 - Financial Statements and Supplementary Data
- Part II, Item 9A - Controls and Procedures
- Part IV, Item 15 - Exhibits, Financial Statement Schedules

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Forward-Looking Statements

This Annual Report on Form 10-K (“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 and information currently available to us. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Certain words in this Annual Report such as “anticipate,” “believe,” “could,” “estimate,” “expect,” “forecast,” “goal,” “intend,” “may,” “plan,” “project,” “will,” and similar expressions and statements regarding our plans and objectives for future operations, identify forward-looking statements. Although we and our general partner believe such forward-looking statements are reasonable, neither we nor our general partner can assure they will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those expected. Among the key risk factors that may impact our consolidated financial position and results of operations are:

- the prices of crude oil, natural gas liquids, refined products, ethanol, and biodiesel;
- energy prices generally;
- the general level of crude oil, natural gas, and natural gas liquids production;
- the general level of demand for crude oil, natural gas liquids, refined products, ethanol, and biodiesel;
- the availability of supply of crude oil, natural gas liquids, refined products, ethanol, and biodiesel;
- the level of crude oil and natural gas drilling and production in producing areas where we have water treatment and disposal facilities;
- the prices of propane and distillates relative to the prices of alternative and competing fuels;
- the price of gasoline relative to the price of corn, which impacts the price of ethanol;
- the ability to obtain adequate supplies of products if an interruption in supply or transportation occurs and the availability of capacity to transport products to market areas;
- actions taken by foreign oil and gas producing nations;
- the political and economic stability of foreign oil and gas producing nations;
- the effect of weather conditions on supply and demand for crude oil, natural gas liquids, refined products, ethanol, and biodiesel;
- the effect of natural disasters, lightning strikes, or other significant weather events;
- the availability of local, intrastate and interstate transportation infrastructure with respect to our truck, railcar, and barge transportation services;
- the availability, price, and marketing of competing fuels;
- the impact of energy conservation efforts on product demand;
- energy efficiencies and technological trends;
- governmental regulation and taxation;
- the impact of legislative and regulatory actions on hydraulic fracturing, waste water disposal and on the treatment of flowback and produced water;
- hazards or operating risks related to transporting and distributing petroleum products that may not be fully covered by insurance;
- the maturity of the crude oil, natural gas liquids, and refined products industries and competition from other marketers;
- loss of key personnel;
- the ability to renew contracts with key customers;
- the ability to maintain or increase the margins we realize for our terminal, barging, trucking, water disposal, recycling, and discharge services;
- the ability to renew leases for our leased equipment and storage facilities;

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- the nonpayment or nonperformance by our counterparties;
- the availability and cost of capital and our ability to access certain capital sources;
- a deterioration of the credit and capital markets;
- the ability to successfully identify and consummate strategic acquisitions, and integrate acquired assets and businesses;
- changes in the volume of hydrocarbons recovered during the wastewater treatment process;
- changes in the financial condition and results of operations of entities in which we own noncontrolling equity interests;
- changes in applicable laws and regulations, including tax, environmental, transportation and employment regulations, or new interpretations by regulatory agencies concerning such laws and regulations and the impact of such laws and regulations (now existing or in the future) on our business operations;
- the costs and effects of legal and administrative proceedings;
- any reduction or the elimination of the federal Renewable Fuel Standard; and
- changes in the jurisdictional characteristics of, or the applicable regulatory policies with respect to, our pipeline assets.

You should not put undue reliance on any forward-looking statements. All forward-looking statements speak only as of the date of this Annual Report. Except as required by state and federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements as a result of new information, future events, or otherwise. When considering forward-looking statements, please review the risks described under Part I, Item 1A–“Risk Factors.”

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PART I

References in this Annual Report to (i) "NGL Energy Partners LP," the "Partnership," "we," "our," "us," or similar terms refer NGL Energy Partners LP and its operating subsidiaries, (ii) "NGL Energy Holdings LLC" or "general partner" refers to NGL Energy Holdings LLC, our general partner, (iii) "NGL Energy Operating LLC" or "operating company" refers to NGL Energy Operating LLC, the direct operating subsidiary of NGL Energy Partners LP, (iv) the "NGL Energy GP Investor Group" refers to, collectively, the 42 individuals and entities that own all of the outstanding membership interests in our general partner, and (v) the "NGL Energy LP Investor Group" refers to, collectively, the 15 individuals and entities that owned all of our outstanding common units before the closing date of our initial public offering.

We have presented operational data in Part I, Item 1–"Business" for the year ended March 31, 2016. Unless otherwise indicated, this data is as of March 31, 2016.

Item 1. Business

Overview

We are a Delaware limited partnership formed in September 2010. Subsequent to our initial public offering ("IPO") in May 2011, we significantly expanded our operations through numerous acquisitions. At March 31, 2016, our operations include:

- Our crude oil logistics segment, the assets of which include owned and leased crude oil storage terminals and pipeline injection stations, a fleet of owned trucks and trailers, a fleet of owned and leased railcars, a fleet of owned barges and towboats, and interests in two crude oil pipelines. Our crude oil logistics segment purchases crude oil from producers and transports it to refineries or for resale at owned and leased pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs.
- Our water solutions segment, the assets of which include water pipelines, water treatment and disposal facilities, washout facilities, and solid waste disposal facilities. Our water solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms and drilling fluids and performs truck washouts. In addition, our water solutions segment sells the recycled water and recovered hydrocarbons that result from performing these services.
- Our liquids segment, which supplies natural gas liquids to retailers, wholesalers, refiners, and petrochemical plants throughout the United States and in Canada, and which provides natural gas liquids terminaling and storage services through its 19 owned terminals throughout the United States, its salt dome storage facility in Utah, and its leased storage and railcar transportation services through its fleet of leased railcars.
- Our retail propane segment, which sells propane, distillates, and equipment and supplies to end users consisting of residential, agricultural, commercial, and industrial customers and to certain resellers in 25 states and the District of Columbia.
- Our refined products and renewables segment, which conducts gasoline, diesel, ethanol, and biodiesel marketing operations. We purchase refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedule them for delivery at various locations. See "Dispositions " below for a discussion of our interests in TransMontaigne Partners L.P. ("TLP").

For more information regarding our reportable segments, please see Note 13 to our consolidated financial statements included in this Annual Report.

Acquisitions

Subsequent to our IPO in May 2011, we significantly expanded our operations through numerous acquisitions, including the following, among others:

Year Ended March 31, 2012

- In October 2011, we completed a business combination with E. Osterman Propane, Inc., its affiliated companies, and members of the Osterman family (collectively, “Osterman”), whereby we acquired retail propane operations in the northeastern United States.

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- In November 2011, we completed a business combination with SemStream, L.P. ("SemStream"), whereby we acquired SemStream's wholesale natural gas liquids supply and marketing operations and its 12 natural gas liquids terminals.
- In January 2012, we completed a business combination with seven companies associated with Pacer Propane Holding, L.P. (collectively, "Pacer"), whereby we acquired retail propane operations, primarily in the western United States.
- In February 2012, we completed a business combination with North American Propane, Inc., whereby we acquired retail propane and distillate operations in the northeastern United States.

Year Ended March 31, 2013

- In May 2012, we acquired the retail propane and distillate operations of Downeast Energy Corp. These operations are primarily in the northeastern United States.
- In June 2012, we completed a business combination with High Sierra Energy, LP and High Sierra Energy GP, LLC (collectively, "High Sierra"), whereby we acquired all of the ownership interests in High Sierra. High Sierra's businesses include crude oil gathering, transportation and marketing; water treatment, disposal, and transportation; and natural gas liquids transportation and marketing.
- In November 2012, we completed a business combination whereby we acquired Pecos Gathering & Marketing, L.L.C. and certain of its affiliated companies (collectively, "Pecos"). The business of Pecos consists primarily of crude oil purchasing and logistics operations in Texas and New Mexico.
- In December 2012, we completed a business combination whereby we acquired all of the membership interests in Third Coast Towing, LLC ("Third Coast"). The business of Third Coast consists primarily of transporting crude oil via barge.

Year Ended March 31, 2014

- In July 2013, we completed a business combination whereby we acquired the operating assets of Crescent Terminals, LLC, which operates a leased crude oil storage and dock facility in Port Aransas, Texas, and the ownership interests in Cierra Marine, LP and its affiliated companies (collectively, "Crescent"), whereby we acquired a fleet of four towboats and seven crude oil barges operating in the intercoastal waterways of Texas.
- In July 2013, we completed a business combination with High Roller Wells Big Lake SWD No. 1, Ltd., whereby we acquired a water treatment and disposal facility in the Permian Basin in Texas. We also entered into a development agreement that requires us to purchase water solutions facilities developed by the other party to the agreement. During March 2014, we purchased one additional facility under this development agreement.
- In August 2013, we completed a business combination whereby we acquired seven entities affiliated with Oilfield Water Lines LP (collectively, "OWL"). The businesses of OWL include four water treatment and disposal facilities in the Eagle Ford shale play in Texas.
- In September 2013, we completed a business combination with Coastal Plains Disposal #1, LLC ("Coastal"), whereby we acquired the ownership interests in three water treatment and disposal facilities in the Eagle Ford shale play in Texas, and the option to acquire an additional facility, which we exercised in March 2014.
- In December 2013, we acquired the ownership interests in Gavilon, LLC ("Gavilon Energy"). The assets of Gavilon Energy include crude oil terminals in Oklahoma, Texas and Louisiana, a 50% interest in Glass Mountain Pipeline, LLC ("Glass Mountain"), which owns a crude oil pipeline that originates in western Oklahoma and terminates in Cushing, Oklahoma and became operational in February 2014, and an interest in an ethanol production facility in the Midwest. The operations of Gavilon Energy include the marketing of crude oil, refined products, ethanol, biodiesel, and natural gas liquids, and also include crude oil storage in Cushing, Oklahoma.

Year Ended March 31, 2015

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In July 2014, we acquired TransMontaigne Inc. ("TransMontaigne"). As part of this transaction, we also purchased inventory from the previous owner of TransMontaigne. The operations of TransMontaigne include the marketing of refined products. As part of this transaction, we acquired the 2% general partner interest, the incentive distribution rights, a 19.7% limited partner interest in TLP, and assumed certain terminaling service

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agreements with TLP from an affiliate of the previous owner of TransMontaigne. See “Dispositions” below for a discussion of the sale of the general partner interest.

- In November 2014, we acquired two saltwater disposal facilities in the Bakken shale play in North Dakota.
- In February 2015, we acquired Sawtooth NGL Caverns, LLC (“Sawtooth”), which owns a natural gas liquids salt dome storage facility in Utah with rail and truck access to western United States markets and entered into a construction agreement to expand the storage capacity of the facility.
- During the year ended March 31, 2015, we purchased 16 water treatment and disposal facilities under the development agreement discussed above.
- During the year ended March 31, 2015, we acquired eight retail propane businesses.

Year Ended March 31, 2016

- In August 2015, we acquired four saltwater disposal facilities and a 50% interest in an additional saltwater disposal facility in the Delaware Basin of the Permian Basin in Texas.
- In January 2016, we acquired a 57.125% interest in an existing produced water pipeline company operating in the Delaware Basin portion of West Texas.
- During the year ended March 31, 2016, we purchased 15 water treatment and disposal facilities under the development agreement discussed above.
- During the year ended March 31, 2016, we acquired six retail propane businesses.

Dispositions

Sale of General Partner Interest in TLP

On February 1, 2016, we completed the sale of our general partner interest in TLP to an affiliate of ArcLight Capital Partners (“ArcLight”) for $350 million in cash. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting. As part of this transaction, we entered into lease agreements whereby we will remain the long-term exclusive tenant in the TLP Southeast terminal system. In addition, we retained TransMontaigne’s marketing business, which is a significant part of our refined products and renewables segment, and TransMontaigne Product Services, LLC, its customer contracts and its line space on the Colonial and Plantation pipelines.

Sale of TLP Common Units

On April 1, 2016, we sold all of the TLP common units we owned to ArcLight for approximately $112.4 million in cash.

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Primary Service Areas

The following map shows the primary service areas of our businesses:

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Organizational Chart

The following chart summarizes our legal entity structure at April 1, 2016:

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Our Business Strategies

Our principal business objective is to increase the quarterly distributions that we pay to our unitholders over time while ensuring the ongoing stability of our business and its cash flows. We expect to achieve this objective by executing the following strategies:

- Focus on building a vertically integrated midstream master limited partnership providing multiple services to customers. We continue to enhance our ability to transport crude oil from the wellhead to refiners, refined products from refiners to customers, wastewater from the wellhead to treatment for disposal, recycle, or discharge, and natural gas liquids from processing plants to end users, including retail propane customers.
- Achieve organic growth by investing in new assets that increase volumes, enhance our operations, and generate attractive rates of return. We believe that there are accretive organic growth opportunities that originate from assets we own and operate. We have and expect to continue to invest within our existing businesses, particularly within our crude oil logistics, water solutions, and refined products businesses as we grow these businesses with highly accretive, fee-based organic growth opportunities.
- Deliver accretive growth through strategic acquisitions that complement our existing business model and expand our operations. We intend to continue to pursue acquisitions that build upon our vertically integrated business model, add scale to our current operating platforms, and enhance our geographic diversity in our businesses. We have established a successful track record of acquiring companies and assets at attractive prices and we continue to evaluate acquisition opportunities in order to capitalize on this strategy in the future.
- Focus on consistent annual cash flows by adding operations that minimize commodity price risk and generate fee-based, cost-plus, or margin-based revenues under multi-year contracts. We intend to focus on long-term fee-based contracts in addition to back-to-back contracts which minimize commodity price exposure. We continue to increase cash flows that are supported by certain fee-based, multi-year contracts, some of which include acreage dedications from producers or volume commitments. We also believe that expanding our retail propane business with an emphasis on a high level of residential customers with company-owned tanks will result in strong customer retention rates and consistent operating margins.
- Maintain a disciplined capital structure characterized by low leverage. We target leverage levels that are consistent with those of investment grade companies. Through our disciplined approach to leverage, we expect to maintain sufficient liquidity to manage existing and future capital requirements and to take advantage of market opportunities.
- Maintain a disciplined cash distribution policy that complements our leverage, acquisition and organic growth strategies. We intend to use cash flows from our operations to make distributions to our unitholders and to use excess cash flows to finance organic growth and opportunistically repay indebtedness, including amounts outstanding under our Revolving Credit Facility (as hereinafter defined). We believe this strategy positions us to pursue future acquisitions and to execute upon our organic growth initiatives.

Our Competitive Strengths

We believe that we are well positioned to successfully execute our business strategies and achieve our principal business objective because of the following competitive strengths:

- Our vertically integrated and diversified operations, which help us generate more predictable and stable cash flows on a year-to-year basis. Our ability to provide multiple services to customers in numerous geographic areas enhances our competitive position. Our five businesses units are diversified by geography, customer-base and commodity sensitivities which we believe proves us with the ability to maintain cash flows throughout typical commodity cycles. By examples, our retail propane business sources propane through our liquids business which allows us to leverage the expertise of our liquids business to help improve our margins and profitability and enhance our cash flows. Furthermore, we believe that our liquids business provides us with valuable market intelligence that helps us identify potential acquisition opportunities. Our refined products and retail propane businesses benefit from lower energy prices driving increased customer demand, which can offset the downward pressure on our crude logistics and water businesses in a low price environment.

- Our network of crude oil transportation assets, which allows us to serve customers over a wide geographic area and optimize sales. Our strategically deployed railcar fleet, towboats, barges, and trucks, and our owned and

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contracted pipeline capacity, provide access to a wide range of customers and markets. We use this expansive network of transportation assets to deliver crude oil to the optimal markets.

- Our water processing facilities, which are strategically located near areas of high crude oil and natural gas production. Our water processing facilities are located among the most prolific crude oil and natural gas producing areas in the United States, including the Permian Basin, the DJ Basin, the Eagle Ford shale play, the Bakken shale play, and the Pinedale Anticline. In addition, we believe that the technological capabilities of our water solutions business can be quickly implemented at new facilities and locations.
- Our network of natural gas liquids transportation, terminal, and storage assets, which allow us to provide multiple services over the continental United States. Our strategically located terminals, large railcar fleet, shipper status on common carrier pipelines, and substantial leased and owned underground storage enable us to be a preferred purchaser and seller of natural gas liquids.
- Our high percentage of retail sales to residential customers, who are generally more stable purchasers of propane and distillates and generate higher margins than other customers. Our high percentage of propane tank ownership, payment billing systems, and automatic delivery program have resulted in a strong record of customer retention and help us better predict our cash flows in the retail propane business.
- Our access to refined products pipeline and terminal infrastructure. Our capacity allocations on third-party pipelines and our access to TLP's refined products terminals give us the opportunity to serve customers over a large geographic area.

- Our seasoned management team with extensive midstream industry experience and a track record of acquiring, integrating, operating and growing successful businesses. Our management team has significant experience managing companies in the energy industry, including master limited partnerships. In addition, through decades of experience, our management team has developed strong business relationships with key industry participants throughout the United States. We believe that our management's knowledge of the industry, relationships within the industry, and experience in identifying, evaluating and completing acquisitions provides us with opportunities to grow through strategic and accretive acquisitions that complement or expand our existing operations.

Our Businesses

Crude Oil Logistics

Overview. Our crude oil logistics segment purchases crude oil from producers and transports it to refineries or for resale at owned and leased pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs. We also lease space and capacity in our owned assets, such as storage tanks, pipelines, trucks, barges, and railcars, to third parties for a fee. Our operations are centered near areas of high crude oil production, such as the Bakken shale play in North Dakota, the DJ Basin in Colorado, the Mississippi Lime shale play in Oklahoma, the Permian Basin in Texas and New Mexico, the Eagle Ford shale play in Texas, the Anadarko Basin in Oklahoma and Texas, and southern Louisiana at the Gulf of Mexico.

Operations. We purchase crude oil from producers and transport it to refineries or for resale. Our strategically deployed railcar fleet, towboats, barges, and trucks, and our owned and contracted pipeline capacity, provide access to a wide range of customers and markets. We use this expansive network of transportation assets to deliver crude oil to the optimal markets.

We currently transport crude oil using the following assets:

- 200 owned trucks and 270 owned trailers operating primarily in the Mid-Continent, Permian Basin, Eagle Ford shale play, and Rocky Mountain regions;
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- 400 owned railcars and 600 leased railcars operating primarily in Colorado, New Mexico, North Dakota, Oklahoma, Wyoming, and West Texas; and
- 11 owned towboats and 24 owned barges operating primarily in the intercoastal waterways of the Gulf Coast and along the Mississippi and Arkansas river systems.

Of our 400 owned railcars, all are compliant with the standards for railcars built subsequent to 2011. Of our 600 leased railcars, 100 are compliant with these standards (see Part I, Item 1A–"Risk Factors).

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We contract for truck, rail, and barge transportation services from third parties and ship on 17 common carrier pipelines. We own 35 pipeline injection stations, the locations of which are summarized below.

State	Number of Pipeline Injection Stations
Texas	14
Oklahoma	9
New Mexico	5
Kansas	3
North Dakota	3
Montana	1
Total	35

We also lease three pipeline injection stations in Montana and North Dakota. We also have commitments on several interstate pipelines for transportation of crude oil.

We own seven storage terminal facilities. The largest of these is a terminal in Cushing, Oklahoma with a storage capacity of 4,600,000 barrels, including 1,000,000 barrels which are owned by Glass Mountain. The combined storage capacity of the other six terminals is 462,500 barrels.

We lease 2,052,500 barrels of capacity at two storage terminal facilities. Of this leased storage capacity, 2,000,000 barrels are at Cushing, Oklahoma.

We have one Gulf Coast terminal facility that is under construction and is expected to be completed during the second quarter of fiscal year 2017 with a total expected storage capacity of 285,000 barrels. We own a 50% interest in Glass Mountain, which owns a 210-mile crude oil pipeline that originates in western Oklahoma and terminates in Cushing, Oklahoma. This pipeline, which became operational in February 2014, has a capacity of 147,000 barrels per day.

In September 2014, we entered into a joint venture with RimRock Midstream, LLC (“RimRock”) whereby each party owned a 50% interest in Grand Mesa Pipeline, LLC (“Grand Mesa”). In October 2014, we obtained ship-or-pay volume commitments from multiple shippers to begin construction of the Grand Mesa Pipeline, which will originate in Colorado and terminate in Cushing, Oklahoma. In November 2014, we acquired RimRock’s 50% ownership interest in Grand Mesa for $310.0 million in cash. In November 2015, Grand Mesa Pipeline entered into an agreement with Saddlehorn Pipeline Company, LLC (“Saddlehorn”), under which we acquired a 37.5% undivided interest in a crude oil pipeline currently under construction (the “Joint Pipeline”). The Joint Pipeline will take receipt from Grand Mesa Pipeline’s origin in Colorado and will deliver to Cushing, Oklahoma. We will have the right to utilize 150,000 barrels per day of capacity on the Joint Pipeline. Operating costs will be allocated to us based on our proportionate ownership interest and throughput. We expect the Joint Pipeline to be operational beginning in the third quarter of fiscal year 2017.

Through our undivided interest in the Joint Pipeline, we will have expanded capacity, sufficient to service our customer contracts at the same origin and termination points with the ability to accept additional volume commitments. We will retain ownership of our previously-acquired easements for the potential future development of transportation projects involving petroleum commodities other than crude oil and condensate. With the consent and participation of Saddlehorn, we and Saddlehorn may consider future opportunities using these easements for projects involving the transportation of crude oil and condensate.

Customers. Our customers include crude oil refiners, producers, and marketers. During the year ended March 31, 2016, 65% of the revenues of our crude oil logistics segment were generated from our ten largest customers of the segment. In addition to utilizing our assets to transport crude oil we own, we also provide truck transportation, barge transportation, storage, and terminal throughput services to our customers.

Competition. Our crude oil logistics business faces significant competition, as many entities are engaged in the crude oil logistics business, some of which are larger and have greater financial resources than we do. The primary factors on which we compete are:

- price;
- availability of supply;

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- reliability of service;
- logistics capabilities, including the availability of railcars, proprietary terminals, and owned pipelines, barges, railcars, trucks, and towboats;
- long-term customer relationships; and
- the acquisition of businesses.

Supply. We obtain crude oil from a large base of suppliers, which consists primarily of crude oil producers. We currently purchase crude oil from approximately 350 producers at approximately 4,300 leases.

Pricing Policy. Most of our contracts to purchase or sell crude oil are at floating prices that are indexed to published rates in active markets such as Cushing, Oklahoma. We seek to manage price risk by entering into purchase and sale contracts of similar volumes based on similar indexes and by hedging exposure due to fluctuations in actual volumes and scheduled volumes.

Our profitability is impacted by forward crude oil prices. Crude oil markets can either be in contango (a condition in which forward crude oil prices are greater than spot prices) or can be backwardated (a condition in which forward crude oil prices are lower than spot prices). Our crude oil logistics business benefits when the market is in contango, as increasing prices result in inventory holding gains during the time between when we purchase inventory and when we sell it. In addition, we are able to better utilize our storage assets when crude oil markets are in contango. When markets are backwardated, falling prices typically have an unfavorable impact on our margins.

Billing and Collection Procedures. Our crude oil logistics customers consist primarily of crude oil refiners, producers, and marketers. We typically invoice these customers on a monthly basis. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on our crude oil logistics customers. We believe the following procedures enhance our collection efforts with our crude oil logistics customers:

- we require certain customers to prepay or place deposits for our services;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we review receivable aging analyses regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers' receivable position and suspend sales to customers that have not timely paid invoices.

Trade Names. Our crude oil logistics segment operates primarily under the NGL Crude Logistics, NGL Crude Transportation and NGL Marine trade names.

Water Solutions

Overview. Our water solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms and drilling fluids and performs truck washouts. In addition, our water solutions segment sells the recycled water and recovered hydrocarbons that result from performing these services. Our water processing facilities are strategically located near areas of high crude oil and natural gas production, including the Permian Basin in Texas, the DJ Basin in Colorado, the Eagle Ford shale play in Texas, the Bakken shale play in North Dakota, and the Pinedale Anticline in Wyoming. During the year ended March 31, 2016, we took delivery of 208.4 million barrels of wastewater, an average of 571,000 barrels per day.

Our water solutions segment is in the process of expanding its solids disposal business. With the addition of specialized equipment to select facilities in the Eagle Ford shale play, the Permian Basin, and the DJ Basin, we are able to accept and dispose of solids such as tank bottoms and drilling fluids generated by crude oil and natural gas exploration and production activities. Our facilities will accept only exploration and production exempt waste allowed under our current permits.

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Operations. We own 70 water treatment and disposal facilities, including 87 wells. The location of the facilities and the processing capacities at which the facilities currently operate are summarized below.

Location	Processing Capacity (barrels per day)	Located on Land We Own or Lease
Pinedale Anticline (1)	60,000	Lease
DJ Basin (2)	189,500	Own
DJ Basin	72,500	Lease
Total-DJ Basin	262,000	
Permian Basin (3)	653,000	Own
Eagle Ford Shale Play (3)	304,000	Own
Eagle Ford Shale Play (3)	169,000	Lease
Total-Eagle Ford Shale Play	473,000	
Eaglebine Shale Play	20,000	Own
Granite Wash Shale Play (3)	52,000	Own
Bakken Shale Play	30,000	Own
Bakken Shale Play	16,000	Lease
Total-Bakken Shale Play	46,000	
Total-All Facilities	1,566,000	

(1) This facility has a design capacity of 60,000 barrels per day to process water to a recycle standard which also includes a design capacity of 15,000 barrels per day to process water to a discharge standard.

(2) Reflects the total processing capacity of facilities located on land we own at this location, which includes two facilities that have a combined design capacity of 20,000 barrels per day to process water to a recycle standard.

(3) Certain facilities can dispose of both wastewater and solids such as tank bottoms and drilling fluids. We own a 50% interest in the disposal of solids.

In the table above, the processing capacity for the Permian Basin includes one facility with a processing capacity of 16,000 barrels per day in which we own a 50% interest. In the table above, the processing capacity for facilities located on land we lease in the Eagle Ford Shale Play includes three facilities with a combined processing capacity of 83,000 barrels per day in which we own a 75% interest.

Our customers bring wastewater generated by crude oil and natural gas exploration and production operations to our facilities for treatment through pipeline gathering systems, which we plan to further expand, and by truck. Once we take delivery of the water, the level of processing is determined by the ultimate disposition of the water. Our solids customers bring solids generated by crude oil and natural gas exploration and production operations to our facilities by truck.

Our facility in Wyoming has the assets and technology needed to treat the water more extensively. At this facility, the water is recycled, rather than being disposed of in an injection well. We either process the water to the point where it can be returned to producers to be reused in future drilling operations (recycle quality water), or we treat the water to a greater extent, such that it exceeds the standards for drinking water, and can be returned to the ecosystem (discharge quality water). Recycling offers producers an alternative to the use of fresh water in hydraulic fracturing operations. This minimizes the impact on aquifers, particularly in arid regions of the United States. Since our merger with High Sierra in June 2012, we have recycled approximately 12 million barrels (504 million gallons) of recycle quality water and have returned approximately 8 million barrels (336 million gallons) of discharge quality water back to New Fork River, which is a tributary of the Colorado River. We also make discharge quality water available to producers and the surrounding community for purposes such as dust control.

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Our facilities in Colorado dispose of wastewater primarily into deep underground formations via injection wells. Two of our facilities in Colorado have the assets and technology needed to treat the water to the point that we can sell the water back to producers for use in future drilling operations.

Our facilities in Texas and North Dakota dispose of wastewater into deep underground formations via injection wells.

At our disposal facilities, we use proprietary well maintenance programs to enhance injection rates and extend the service lives of the wells.

Customers. The customers of our Wyoming and Colorado facilities consist primarily of large exploration and production companies that conduct drilling operations near our facilities. The customers of our Texas and North Dakota facilities consist of both wastewater transportation companies and producers. The primary customer of our Wyoming facility has committed to deliver a specified minimum volume of water to our facility under a long-term contract. The primary customers of our Colorado facilities have committed to deliver all wastewater produced at wells in a designated area to our facilities. One customer in Texas has committed to deliver at least 50,000 barrels of wastewater per day to our facilities. Most customers of our other facilities are not under volume commitments, although certain of our facilities are connected to producer locations by pipeline. During the year ended March 31, 2016, 23% of the water treatment and disposal revenues of our water solutions segment were generated from our two largest customers of the segment, and 52% of the water treatment and disposal revenues of the segment were generated from our ten largest customers of the segment.

Competition. We compete with other processors of wastewater to the extent that other processors have facilities geographically close to our facilities. Location is an important consideration for our customers, who seek to minimize the cost of transporting the wastewater to disposal facilities. Our facilities are strategically located near areas of high crude oil and natural gas production. A significant factor affecting the profitability of our water solutions segment is the extent of exploration and production in the areas near our facilities, which is generally based upon producers' expectations about the profitability of drilling new wells.

Pricing Policy. We generally charge customers a processing fee per barrel of wastewater processed. Certain of our contracts require the customer to deliver a specified minimum volume of wastewater over a specified period of time. We also generate revenue from the sale of hydrocarbons we recover in the process of treating the wastewater, which we take into consideration in negotiating the processing fees with our customers.

Billing and Collection Procedures. Our water solutions customers consist of large crude oil and natural gas producers, and also include smaller water transportation companies. We typically invoice customers on a monthly basis. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on our water solutions customers. We believe the following procedures enhance our collection efforts with our water solutions customers:

- we require certain customers to prepay or place deposits for our services;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we review receivable aging analyses regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers' receivable position and suspend service to customers that have not timely paid invoices.

Trade Names. Our water solutions segment operates primarily under the NGL Water Solutions and Anticline Disposal trade names.

Technology. We hold multiple patents for processing technologies. We own a research and development center, which we use to optimize treatment processes and cost minimization. We believe that the technological capabilities of our water solutions business can be quickly implemented at new facilities and locations.

Liquids

Overview. Our liquids segment provides natural gas liquids procurement, storage, transportation, and supply services to customers through assets owned by us and third parties. Our liquids business also supplies the majority of the propane for our retail propane business. We also sell butanes and natural gasolines to refiners and producers for use as blending stocks and diluent and assist refineries by managing their seasonal butane supply needs. During the year ended March 31, 2016, we sold 2.1 billion gallons of natural gas liquids, an average of 5.72 million gallons per day.

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Operations. We procure natural gas liquids from refiners, gas processing plants, producers and other resellers for delivery to leased or owned storage space, common carrier pipelines, railcar terminals, and direct to certain customers. Our customers take delivery by loading natural gas liquids into transport vehicles from common carrier pipeline terminals, private terminals, our terminals, directly from refineries and rail terminals, and by railcar.

A portion of our wholesale propane gallons are presold to third-party retailers and wholesalers at a fixed price under back-to-back contracts. Back-to-back contracts, in which we balance our contractual portfolio by buying propane supply when we have a matching purchase commitment from our wholesale customers, protects our margins, and mitigates commodity price risk. Presales also reduce the impact of warm weather because the customer is required to take delivery of the propane regardless of the weather. We generally require cash deposits from these customers. In addition, on a daily basis we have the ability to balance our inventory by buying or selling propane, butanes, and natural gasoline to refiners, resellers, and propane producers through pipeline inventory transfers at major storage hubs.

In order to secure consistent supply during the heating season, we are often required to purchase volumes of propane during the entire fiscal year. In order to mitigate storage costs and price risk, we may sell those volumes at a lesser margin than we earn in our other wholesale operations.

We purchase butane from refiners during the summer months, when refiners have a greater butane supply than they need, and sell butane to refiners during the winter blending season, when demand for butane is higher. We utilize a portion of our railcar fleet and a portion of our leased underground storage to store butane for this purpose.

We also transport customer-owned natural gas liquids on our leased railcars and charge the customers a transportation service fee. In addition, we sublease railcars to certain customers.

In addition, we purchase and sell asphalt. We utilize leased railcars to move the asphalt from our suppliers to our customers.

We own 19 natural gas liquids terminals and we lease a fleet of railcars. These assets give us the opportunity to access wholesale markets throughout the United States, and to move product to locations where demand is highest. We utilize these terminals and railcars primarily in the service of our wholesale operations, although we also provide transportation, storage, and throughput services to other parties to a lesser extent.

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The following table summarizes our natural gas liquids terminals and their throughput capacity:

Facility	Throughput Capacity (gallons per day)
Rosemount, Minnesota	1,441,000
Lebanon, Indiana	1,058,000
West Memphis, Arkansas	1,058,000
Dexter, Missouri	930,000
East St. Louis, Illinois	883,000
Jefferson City, Missouri	883,000
St. Catharines, Ontario, Canada	700,000
Janesville, Wisconsin	553,000
Light, Arkansas	524,400
Rixie, Arkansas	524,400
West Springfield, Massachusetts	441,000
Albuquerque, New Mexico	408,000
Portland, Maine	360,000
Vancouver, Washington	358,000
Green Bay, Wisconsin	310,000
Ritzville, Washington	198,000
Thackerville, Oklahoma	180,000
Shelton, Washington	161,000
Superior, Montana (1)	120,000
Total	11,090,800

(1) We own a terminal in Superior, Montana with throughput of 120,000 gallons per day that we are currently subleasing through October 2017 with an option to extend or to purchase.

We are currently building a rail terminal at the Port of Little Rock, Arkansas capable of receiving natural gas liquids by railcar, storing, and loading out via truck. The throughput capacity for this terminal is expected to be 120,000 gallons per day. We expect this terminal to be operational by June 30, 2016. Also, during the year ended March 31, 2016, we reached an agreement with the state of Maine’s Department of Transportation and, as of the end of April 2016, the Portland, Maine facility was shut down.

We have operating agreements with third parties for certain of our terminals. The terminals in East St. Louis, Illinois and Jefferson City, Missouri are operated for us by a third party for a monthly fee under an operating and maintenance agreement that expires in 2017. The terminal in St. Catherines, Ontario, Canada is operated by a third party under a year-to-year agreement.

We own the terminal assets. We own the land on which twelve of the terminals are located and we either have easements or lease the land on which seven of the terminals are located. The terminals in East St. Louis, Illinois and Jefferson City, Missouri have perpetual easements, and the terminal in St. Catharines, Ontario, Canada has a long-term lease that expires in 2022.

We own an underground storage facility near Delta, Utah. This facility currently has capacity to store approximately 4.2 million barrels of natural gas liquids. We have begun construction of a new cavern to expand the storage capacity, and we expect the new cavern to be operational in the second quarter of fiscal year ending March 31, 2017. We lease storage to 15 customers, with lease terms ranging from one to three years. The facility is located on property for which we have a long-term lease.

We lease 4,838 railcars, of which 765 are subleased to a third party. These include high pressure and general-purpose railcars.

We own 23 transloading units, which enable customers to transfer product from railcars to trucks. These transloading units can be moved to locations along a railroad where it is most convenient for customers to transfer their product.

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We lease natural gas liquids storage space to accommodate the supply requirements and contractual needs of our retail and wholesale customers. We lease storage space for natural gas liquids in various storage hubs in Arizona, Canada, Kansas, Mississippi, Missouri, and Texas.

The following table summarizes our significant leased storage space at natural gas liquids storage facilities and interconnects to those facilities:

Storage Facility	Leased Storage Space (gallons) Beginning April 1, 2016	At March 31, 2016	Storage Interconnects
Conway, Kansas	64,890,000	64,940,000	Connected to Enterprise Mid-America and NuStar Pipelines; Rail Facility
Borger, Texas	42,000,000	42,000,000	Connected to ConocoPhillips Blue Line Pipeline
Corunna, Ontario, Canada	15,800,000	2,100,000	Rail Facility
Bushton, Kansas	12,600,000	12,600,000	Connected to ONEOK North System Pipeline
Hattiesburg, Mississippi	9,660,000	6,300,000	Connected to Enterprise Dixie Pipeline; Rail Facility
Carthage, Missouri	7,560,000	7,560,000	Connected to Mid-America Pipeline
Redwater, Alberta, Canada	4,370,000	9,072,000	Connected to Cochin Pipeline; Rail Facility
Mont Belvieu, Texas	2,940,000	2,940,000	Connected to Enterprise Texas Eastern Products Pipeline
Napoleonville, LA	2,407,000	—	Connected to Enlink Pipeline; Rail Facility
Adamana, Arizona	1,680,000	1,680,000	Rail Facility
St. Clair, Michigan	—	6,300,000	Rail Facility
Marysville, Michigan	—	2,100,000	Connected to Cochin Pipeline
Total	163,907,000	157,592,000	

During the typical heating season from September 15 through March 15 each year, we have the right to utilize ConocoPhillips' capacity as a shipper on the Blue Line pipeline to transport natural gas liquids from our leased storage space to our terminals in East St. Louis, Illinois and Jefferson City, Missouri. During the remainder of the year, we have access to available capacity on the Blue Line pipeline on the same basis as other shippers.

Customers. Our liquids business serves approximately 900 customers in 48 states. Our liquids business serves national, regional and independent retail, industrial, wholesale, petrochemical, refiner and natural gas liquids production customers. Our liquids business also supplies the majority of the propane for our retail propane business. We deliver the propane supply to our customers at terminals located on common carrier pipelines, rail terminals, refineries, and major United States propane storage hubs. During the year ended March 31, 2016, 34% of the revenues of our liquids segment were generated from our ten largest customers of the segment (exclusive of sales to our retail propane segment).

Seasonality. Our wholesale propane business is affected by the weather in a similar manner as our retail propane business as discussed below. However, we are able to partially mitigate the effects of seasonality by preselling a portion of our wholesale volumes to retailers and wholesalers and requiring the customer to take delivery regardless of the weather.

Competition. Our liquids business faces significant competition, as many entities, including other natural gas liquids wholesalers and companies involved in the natural gas liquids midstream industry (such as terminal and refinery operations), are engaged in the liquids business, some of which have greater financial resources than we do. The primary factors on which we compete are:

- price;
- availability of supply;
- reliability of service;
- available space on common carrier pipelines;
- storage availability;

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- logistics capabilities, including the availability of railcars, and proprietary terminals;
- long-term customer relationships; and
- the acquisition of businesses.

Pricing Policy. In our liquids business, we offer our customers three categories of contracts for propane sourced from common carrier pipelines:

- customer pre-buys, which typically require deposits based on market pricing conditions;
- market based, which can either be a posted price or an index to spot price at time of delivery; and
- load package, a firm price agreement for customers seeking to purchase specific volumes delivered during a specific time period.

We use back-to-back contracts for many of our liquids segment sales to limit exposure to commodity price risk and protect our margins. We are able to match our supply and sales commitments by offering our customers purchase contracts with flexible price, location, storage, and ratable delivery. However, certain common carrier pipelines require us to keep minimum in-line inventory balances year round to conduct our daily business, and these volumes may not be matched with a purchase commitment.

We generally require deposits from our customers for fixed priced future delivery of propane if the delivery date is more than 30 days after the time of contractual agreement.

Billing and Collection Procedures. Our liquids segment customers consist of commercial accounts varying in size from local independent distributors to large regional and national retailers. These sales tend to be large volume transactions that can range from 10,000 gallons up to 1,000,000 gallons, and deliveries can occur over time periods extending from days to as long as a year. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on our liquids customers. We believe the following procedures enhance our collection efforts with our liquids customers:

- we require certain customers to prepay or place deposits for their purchases;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we require certain customers to take delivery of their contracted volume ratably to help control the account balance rather than allowing them to take delivery of propane at their discretion;
- we review receivable aging analyses regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers’ receivable position and suspend sales to customers that have not timely paid invoices.

Trade Names. Our liquids segment operates primarily under the NGL Supply Wholesale, NGL Supply Terminal Company, Sawtooth NGL Caverns, Centennial Energy, and Centennial Gas Liquids trade names.

Retail Propane

Overview. Our retail propane segment consists of the retail marketing, sale and distribution of propane and distillates, including the sale and lease of propane tanks, equipment and supplies, to more than 300,000 residential, agricultural, commercial and industrial customers. We also sell propane to certain resellers. We purchase the majority of the propane sold in our retail propane business from our liquids business, which provides our retail propane business with a stable and secure supply of propane. During the year ended March 31, 2016, we sold 182.9 million gallons of propane and distillates, an average of 501,000 gallons per day.

Operations. We market retail propane and distillates through our customer service locations. We sell propane primarily in rural areas, but we also have a number of customers in suburban areas where energy alternatives to propane such as natural gas are not generally available. We own or lease 113 customer service locations and 98 satellite distribution locations, with aggregate propane storage capacity of 11.9 million gallons and aggregate distillate storage capacity of 3.4 million gallons. Our customer service locations are staffed and operated to service a defined geographic market area and typically include a business office, product showroom, and secondary propane storage. Our satellite distribution locations, which are unmanned storage tanks, allow our customer service centers to serve an extended market area.

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Our customer service locations in Illinois and Indiana also rent over 17,000 water softeners and filters, primarily to residential customers in rural areas to treat well water or other problem water. We sell water conditioning equipment and treatment supplies as well. Although the water conditioning portion of our retail propane business is small, it generates steady year round revenues. The customer bases in Illinois and Indiana for retail propane and water conditioning have significant overlap, providing the opportunity to cross-sell both products between those customer bases.

The following table summarizes the number of our customer service locations and satellite distribution locations by state:

State	Number of Customer Service Locations	Number of Satellite Distribution Locations
Illinois	22	20
Maine	15	10
Georgia	14	5
Massachusetts	10	8
North Carolina	10	1
Pennsylvania	8	3
Kansas	8	28
Indiana	4	5
Connecticut	4	2
South Carolina	3	—
New Hampshire	3	4
Oregon	2	1
Washington	2	—
Mississippi	1	3
Maryland	1	1
Rhode Island	1	1
Tennessee	1	1
Utah	1	1
Wyoming	1	1
Colorado	1	—
Vermont	1	2
New Jersey	—	1
Total	113	98

We own 86 of our 113 customer service locations and 66 of our 98 satellite distribution locations, and we lease the remainder.

Tank ownership at customer locations is an important component to our operations and customer retention. At March 31, 2016, we owned the following propane storage tanks:

- 400 bulk storage tanks with capacities ranging from 2,000 to 90,000 gallons; and
- over 300,000 stationary customer storage tanks with capacities ranging from 7 to 30,000 gallons.

We also lease an additional 20 bulk storage tanks.

At March 31, 2016, we owned a fleet of 440 bulk delivery trucks, 40 semi-tractors, 30 propane transport trailers and 520 other service trucks.

Retail deliveries of propane are usually made to customers by means of our fleet of bulk delivery trucks. Propane is pumped from the bulk delivery truck, which holds from 2,400 to 5,000 gallons, into a storage tank at the customer's premises. The capacity of these storage tanks ranges from 50 to 30,000 gallons. We also deliver propane to retail customers in portable cylinders, which typically have a capacity of 5 to 25 gallons. These cylinders are either picked up on a delivery route, refilled at

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our customer service locations, and then returned to the retail customer, or refilled at the customer's location. Customers can also bring the cylinders to our customer service centers to be refilled.

Approximately 70% of our residential customers receive their propane supply via our automatic route delivery program, which allows us to maximize our delivery efficiency. For these customers, our delivery forecasting software system utilizes a customer's historical consumption patterns combined with current weather conditions to more accurately predict the optimal time to refill the customer's tank. The delivery information is then uploaded to routing software to calculate the most cost effective delivery route. Our automatic delivery program promotes customer retention by providing an uninterrupted supply of propane and enables us to efficiently conduct route deliveries on a regular basis. Some of our purchase plans, such as level payment billing, fixed price, and price cap programs, further promote our automatic delivery program.

Customers. Our retail propane and distillate customers fall into three broad categories: residential, commercial and industrial, and agricultural. At March 31, 2016, our retail propane and distillate customers were comprised of:

- 71% residential customers;
- 28% commercial and industrial customers; and
- 1% agricultural customers.

No single customer accounted for more than 1% of our retail propane volumes during the year ended March 31, 2016.

Seasonality. The retail propane and distillate business is largely seasonal due to the primary use of propane and distillates as heating fuels. In particular, residential and agricultural customers who use propane and distillates to heat homes and livestock buildings generally only need to purchase propane during the typical fall and winter heating season. Propane sales to agricultural customers who use propane for crop drying are also seasonal, although the impact on our retail propane volumes sold varies from year to year depending on the moisture content of the crop and the ambient temperature at the time of harvest. Propane and distillate sales to commercial and industrial customers, while affected by economic patterns, are not as seasonal as sales to residential and agricultural customers.

Competition. Our retail propane business faces significant competition, as many entities are engaged in the retail propane business, some of which have greater financial resources than we do. Also, we compete with alternative energy sources, including natural gas and electricity. The primary factors on which we compete are:

- price;
- availability of supply;
- reliability of service;
- long-term customer relationships; and
- the acquisition of businesses.

Competition with other retail propane distributors in the propane industry is highly fragmented and generally occurs on a local basis with other large full-service, multi-state propane marketers, smaller local independent marketers, and farm cooperatives. Our customer service locations generally have one to five competitors in their market area.

The competitive landscape of the markets that we serve has been fairly stable. Each customer service location operates in its own competitive environment, since retailers are located in close proximity to their customers due to delivery economics. Our customer service locations generally have an effective marketing radius of 25 to 55 miles, although in certain areas the marketing radius may be extended by satellite distribution locations.

The ability to compete effectively depends on the ability to provide superior customer service, which includes reliability of supply, quality equipment, well-trained service staff, efficient delivery, 24-hours-a-day service for emergency repairs and deliveries, multiple payment and purchase options and the ability to maintain competitive prices. Additionally, we believe that our safety programs, policies and procedures are more comprehensive than many of our smaller, independent competitors, which offers a higher level of service to our customers. We also believe that our overall service capabilities and customer responsiveness differentiate us from many of our competitors.

Supply. Our retail propane segment purchases the majority of its propane from our liquids segment.

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Pricing Policy. Our pricing policy is an essential element in the successful marketing of retail propane and distillates. We protect our margin by adjusting our retail propane pricing based on, among other things, prevailing supply costs, local market conditions, and input from management at our customer service locations. We rely on our regional management to set prices based on these factors. Our regional managers are advised regularly of any changes in the delivered cost of propane and distillates, potential supply disruptions, changes in industry inventory levels, and possible trends in the future cost of propane and distillates. We believe the market intelligence provided by our liquids business, combined with our propane and distillate pricing methods allows us to respond to changes in supply costs in a manner that protects our customer base and our margins.

Billing and Collection Procedures. In our retail propane business, our customer service locations are typically responsible for customer billing and account collection. We believe that this decentralized and more personal approach is beneficial because our local staff has more detailed knowledge of our customers, their needs, and their history than would an employee at a remote billing center. Our local staff often develops relationships with our customers that are beneficial in reducing payment time for a number of reasons:

- customers are billed on a timely basis;
- customers tend to keep accounts receivable balances current when paying a local business and people they know;
- many customers prefer the convenience of paying in person; and
- billing issues may be handled more quickly because local personnel have current account information and detailed customer history available to them at all times to answer customer inquiries.

Our retail propane customers must comply with our standards for extending credit, which typically includes submitting a credit application, supplying credit references, and undergoing a credit check with an appropriate credit agency.

Trade Names. We use a variety of trademarks and trade names that we own, including Hicksgas, Propane Central, Brantley Gas, Osterman, Pacer, Downeast Energy, Allied Propane, Lessig Oil and Propane, Proflame, Anthem Propane Exchange, Woodstock Gas, and Bernville Quality Fuels, among others. We typically retain and continue to use the names of the companies that we acquire and believe that this helps maintain the local identification of these companies and contributes to their continued success. We regard our trademarks, trade names, and other proprietary rights as valuable assets and believe that they have significant value in the marketing of our products.

Refined Products and Renewables

Overview. Our refined products and renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations. During the year ended March 31, 2016, we sold 99.0 million barrels of refined products, an average of 271,000 barrels per day.

Operations. The refined products we handle include gasoline, diesel fuel, and heating oil. We purchase refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedule them for delivery primarily on the Colonial, Plantation, and Magellan pipelines. On certain interstate pipelines, demand for shipment exceeds the available capacity, and pipeline capacity is allocated to shippers based on their historical shipment volumes. We hold allocated capacity on the Colonial and Plantation pipelines.

A significant percentage of our business is priced on a back-to-back basis which minimizes our commodity price exposure. We sell our products to commercial and industrial end users, independent retailers, distributors, marketers, government entities, and other wholesalers of refined petroleum products. We sell our products at TLP’s terminals and at terminals owned by third parties. As discussed above, on February 1, 2016, we sold our general partner interest in TLP. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting. As part of this transaction, we entered into lease agreements whereby we will remain the long-term exclusive tenant in the TLP Southeast terminal system. In addition, we retained TransMontaigne's marketing business, which is a significant part of our refined products and renewables segment, and TransMontaigne Product Services, LLC, its customer contracts and its line space on the Colonial and Plantation pipelines.

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The following table summarizes our leased storage space at refined products storage facilities:

Locations	Active Storage Capacity (shell barrels)
Southeast Facilities	
Albany, Georgia	203,000
Americus, Georgia	93,000
Athens, Georgia	193,000
Bainbridge, Georgia	372,000
Birmingham, Alabama	178,000
Charlotte, North Carolina	121,000
Collins, Mississippi	200,000
Collins/Purvis, Mississippi	94,000
Doraville, Georgia	438,000
Fairfax, Virginia	508,000
Greensboro, North Carolina	436,000
Griffin, Georgia	107,000
Linden, New Jersey	400,000
Lookout Mountain, Georgia	221,000
Macon, Georgia	174,000
Meridian, Mississippi	139,000
Montvale, Virginia	503,000
Nashville, Tennessee	11,000
Norfolk, Virginia	1,336,000
Port Everglades North, Florida	62,000
Richmond, Virginia	444,000
Rome, Georgia	152,000
Selma, North Carolina	218,000
Spartanburg, South Carolina	166,000
Total Southeast Facilities Storage Capacity	6,769,000
Mid-Continent Facilities	
Magellan North system	202,000
NuStar East Products system	150,000
Total Mid-Continent Facilities Storage Capacity	352,000
Total Facilities Storage Capacity	7,121,000

We purchase ethanol primarily at production facilities in the Midwest and transport the ethanol via trucks and railcars for sale at various locations. We also blend ethanol into gasoline for sale to customers at TLP’s terminals. We market and handle logistics for third-party ethanol manufacturers for a service fee. We purchase biodiesel from production facilities in the Midwest and in Houston, Texas, and transport the biodiesel via railcar to sell to customers. We lease 67,000 barrels of biodiesel storage in Deer Park, Texas and have a biodiesel terminaling agreement at a fuel terminal in Phoenix, Arizona with a minimum monthly throughput requirement. We lease 47 railcars for the transportation of renewables.

Customers. Our refined products and renewables segment serves customers in 39 states. During the year ended March 31, 2016, 34% of the revenues of our refined products and renewables segment were generated from our ten largest customers of the segment. We sell to customers via rack spot sales, contract sales, bulk sales, and just-in-time sales.

Contract sales are made pursuant to negotiated contracts, generally ranging from one to twelve months in duration, that we enter into with local market wholesalers, independent gasoline station chains, heating oil suppliers, and other customers. Contract sales provide these customers with a specified volume of product during the term of the agreement. Delivery of product sold under these arrangements generally is at our truck racks. The pricing of the product delivered under a

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majority of our contract sales is based on published index prices, and varies based on changes in the applicable indices. In addition, at the customer's option, the contract price may be fixed at a stipulated price per gallon.

Rack spot sales are sales that do not involve continuing contractual obligations to purchase or deliver product. Rack spot sales are priced and delivered on a daily basis through truck loading racks. At the end of each day for each of the terminals that we market from, we establish the next day selling price for each product for each of our delivery locations. We announce or "post" to customers via website, e-mail, and telephone communications the rack spot sale price of various products for the following morning. Typical rack spot sale purchasers include commercial and industrial end users, independent retailers and small, independent marketers who resell product to retail gasoline stations or other end users. Our selling price of a particular product on a particular day is a function of our supply at that delivery location or terminal, our estimate of the costs to replenish the product at that delivery location, and our desire to reduce inventory levels at that particular location that day.

Bulk sales generally involve the sale of products in large quantities in the major cash markets including the Houston Gulf Coast and New York Harbor. A bulk sale of products also may be made while the product is being transported in the common carrier pipelines.

We conduct just-in-time sales at a nationwide network of terminals owned by third parties. We post prices at each of these locations on a daily basis. When customers decide to purchase product from us, we purchase the same volume of product from a supplier at a previously agreed-upon price. For these just-in-time transactions, our purchase from the supplier occurs at the same time as our sale to our customer.

Seasonality. The demand for gasoline typically peaks during the summer driving season, which extends from April to September, and declines during the fall and winter months. However, the demand for diesel typically peaks during the fall and winter months due to colder temperatures in the Midwest and Northeast.

Competition. Our refined products and renewables business faces significant competition, as many entities are engaged in the refined products and renewables business, some of which have greater financial resources than we do. The primary factors on which we compete are:

- price;
- availability of supply;
- reliability of service;
- available space on common carrier pipelines;
- storage availability;
- logistics capabilities, including the availability of railcars, and proprietary terminals; and
- long-term customer relationships.

Market Price Risk. Our philosophy is to maintain a minimum commodity price exposure through a combination of purchase contracts, sales contracts and financial derivatives. A significant percentage of our business is priced on a back-to-back basis which minimizes our commodity price exposure. For discretionary inventory, and for those instances where physical transactions cannot be appropriately matched, we utilize financial derivatives to mitigate commodity price exposure. Specific exposure limits are mandated in our credit agreement and in our market risk policy.

The value of refined products in any local delivery market is the sum of the commodity price as reflected on the NYMEX and the basis differential for that local delivery market. The basis differential for any local delivery market is the spread between the cash price in the physical market and the quoted price in the futures markets for the prompt month. We typically utilize NYMEX futures contracts to mitigate commodity price exposure. We generally do not manage the financial impact on us from changes in basis differentials affected by local market supply and demand disruptions.

Legal and Regulatory Considerations. Demand for ethanol and biodiesel is driven in large part by government mandates and incentives. Refiners and producers are required to blend a certain percentage of renewables into their refined products, although the percentage can vary from year to year based on the United States Environmental Protection Agency ("EPA") mandates. In addition, the federal government has in recent years granted certain tax credits for the use of biodiesel, although on several occasions these tax credits have expired. In December 2015, the federal government passed a law to reinstate the tax credit retroactively to January 1, 2015, with the credit expiring on December 31, 2016. Changes in future

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mandates and incentives, or decisions by the federal government related to future reinstatement of the biodiesel tax credit, could result in changes in demand for ethanol and biodiesel.

Billing and Collection Procedures. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on our refined products and renewables customers. We believe the following procedures enhance our collection efforts with our customers:

- we require certain customers to prepay or place deposits for our services;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we monitor individual customer receivables relative to previously-approved credit limits, and our automated rack delivery system gives us the option to discontinue providing product to customers when they exceed their credit limits;
- we review receivable aging analyses regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers' receivable position and suspend sales to customers that have not timely paid invoices.

Trade Names. Our refined products and renewables segment operates primarily under the NGL Crude Logistics and TransMontaigne Product Services LLC trade names.

Employees

At March 31, 2016, we had 3,200 full-time employees. Thirteen of our employees at two of our locations are members of a labor union. We believe that our relations with our employees are satisfactory.

Government Regulation

Regulation of the Oil and Natural Gas Industries

Regulation of Oil and Natural Gas Exploration, Production and Sales. Sales of crude oil and natural gas liquids are not currently regulated and are transacted at market prices. In 1989, the United States Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas. The FERC, which has the authority under the Natural Gas Act to regulate the prices and other terms and conditions of the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all natural gas resellers subject to its regulation, except interstate pipelines, to resell natural gas at market prices. Either Congress or the FERC (with respect to the resale of natural gas in interstate commerce), however, could re-impose price controls in the future.

Exploration and production operations are subject to various types of federal, state and local regulation, including, but not limited to, permitting, well location, methods of drilling, well operations, and conservation of resources. While these regulations do not directly apply to our business, they may affect the businesses of certain of our customers and suppliers and thereby indirectly affect our business.

Regulation of the Transportation and Storage of Natural Gas and Oil and Related Facilities. The FERC regulates oil pipelines under the Interstate Commerce Act and natural gas pipeline and storage companies under the Natural Gas Act, and Natural Gas Policy Act of 1978 (the "NGPA"), as amended by the Energy Policy Act of 2005. While this regulation does not currently apply directly to our facilities, it may affect the price and availability of supply and thereby indirectly affect our business. Additionally, contracts we enter into for the transportation or storage of natural gas or crude oil are subject to FERC regulation including reporting or other requirements. The Joint Pipeline currently under construction by Grand Mesa and Saddlehorn will have several points of origin in Colorado and will terminate in

Cushing, Oklahoma. The transportation services on this pipeline will be subject to FERC regulation once the pipeline commences service. In addition, the intrastate transportation and storage of crude oil and natural gas is subject to regulation by the state in which such facilities are located, and such regulation can affect the availability and price of our supply, and have both a direct and indirect effect on our business.

Anti-Market Manipulation Rules. We are subject to the anti-market manipulation provisions in the Natural Gas Act and the NGPA, as amended by the Energy Policy Act of 2005, which authorizes the FERC to impose fines of up to $1,000,000 per day per violation of the Natural Gas Act, the NGPA, or their implementing regulations. In addition, the Federal Trade Commission ("FTC") holds statutory authority under the Energy Independence and Security Act of 2007 to prevent market

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manipulation in petroleum markets, including the authority to request that a court impose fines of up to $1,000,000 per violation. These agencies have promulgated broad rules and regulations prohibiting fraud and manipulation in oil and gas markets. The Commodity Futures Trading Commission ("CFTC") is directed under the Commodity Exchange Act to prevent price manipulations in the commodity and futures markets, including the energy futures markets. Pursuant to statutory authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1,000,000 per day per violation or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the Commodity Exchange Act. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation.

Maritime Transportation. The Jones Act is a federal law that restricts maritime transportation between locations in the United States to vessels built and registered in the United States and owned and manned by United States citizens. Since we engage in maritime transportation through our barge fleet between locations in the United States, we are subject to the provisions of the law. As a result, we are responsible for monitoring the ownership of our subsidiaries that engage in maritime transportation and for taking any remedial action necessary to ensure that no violation of the Jones Act ownership restrictions occurs. The Jones Act also requires that all United States-flagged vessels be manned by United States citizens. Foreign-flagged seamen generally receive lower wages and benefits than those received by United States citizen seamen. This requirement significantly increases operating costs of United States-flagged vessel operations compared to foreign-flagged vessel operations. Certain foreign governments subsidize their nations' shipyards. This results in lower shipyard costs both for new vessels and repairs than those paid by United States-flagged vessel owners. The United States Coast Guard and American Bureau of Shipping maintain the most stringent regimen of vessel inspection in the world, which tends to result in higher regulatory compliance costs for United States-flagged operators than for owners of vessels registered under foreign flags of convenience.

Environmental Regulation

General. Our operations are subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. Accordingly, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate or imposing additional costs on our operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- delaying construction or system modification or upgrades during permit issuance or renewal;
- requiring investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed to be in non-compliance with permits or permit requirements issued pursuant to or imposed by such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. The trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate.

The following is a discussion of the material environmental laws and regulations that relate to our business.

Hazardous Substances and Waste. We are subject to various federal, state, and local environmental, laws and regulations governing the storage, distribution and transportation of natural gas liquids and the operation of bulk storage LPG terminals, as well as laws and regulations governing environmental protection, including those addressing the discharge of materials into the environment or otherwise relating to protection of the environment. Generally, these laws (i) regulate air and water quality and impose limitations on the discharge of pollutants and establish standards for the handling of solid and hazardous wastes; (ii) subject our operations to certain permitting and registration requirements; (iii) may result in the suspension or revocation of necessary permits, licenses and authorizations; (iv) impose substantial liabilities on us for pollution

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resulting from our operations; (v) require remedial measures to mitigate pollution from former or ongoing operations; and (vi) may result in the assessment of administrative, civil and criminal penalties for failure to comply with such laws. These laws include, among others, the Resource Conservation and Recovery Act (“RCRA”), the Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”), the federal Clean Air Act, the Homeland Security Act of 2002, the Emergency Planning and Community Right to Know Act, the Clean Water Act, the Safe Drinking Water Act, and comparable state statutes. For example, as a flammable substance, propane is subject to risk management plan requirements under section 112(r) of the federal Clean Air Act.

CERCLA, also known as the “Superfund” law, and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the current and past owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. While natural gas liquids are not a hazardous substance within the meaning of CERCLA, other chemicals used in or generated by our operations may be classified as hazardous. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to strict and joint and several liability for the costs of investigating and 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, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

RCRA, and comparable state statutes and their implementing regulations, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil and criminal penalties for alleged non-compliance with RCRA and analogous state requirements. Certain wastes associated with the production of oil and natural gas, as well as certain types of petroleum-contaminated media and debris, are excluded from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated under RCRA’s less stringent solid waste provisions, state laws or other federal laws. It is possible, however, that certain wastes now classified as non-hazardous could be classified as hazardous wastes in the future and therefore be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas wastes as “hazardous wastes.” Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our consolidated results of operations and financial position.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although previous operators have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to implement remedial measures to prevent or mitigate future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our consolidated results of operations or financial position.

Oil Pollution Prevention. Our operations involve the shipment of crude oil by barge through navigable waters of the United States. The Oil Pollution Prevention Act imposes liability for releases of crude oil from vessels or facilities into navigable waters. If a release of crude oil to navigable waters occurred during shipment or from a terminal, we could be subject to liability under the Oil Pollution Prevention Act. We are not currently aware of any facts, events, or conditions related to oil spills that could materially impact our consolidated results of operations or financial position. In 1973, the EPA adopted oil pollution prevention regulations under the Clean Water Act. These oil pollution prevention regulations, as amended several times since their original adoption, require the preparation of a Spill Prevention Control and Countermeasure (“SPCC”) plan for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming crude oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility’s operations comply with the requirements. To be in compliance, the facility’s SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intrafacility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC plan and train personnel in its execution. We maintain and implement such plans for our facilities.

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Air Emissions. Our operations are subject to the federal Clean Air Act and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain permits prior to the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and 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, potentially, criminal enforcement actions. Furthermore, we may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We are aware of planned EPA rulemakings concerning air emissions from the oil and gas industry, but the EPA's schedule for proposing and finalizing these upcoming rulemakings is not presently known.

Water Discharges. The Clean Water Act and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the United States and impose requirements affecting our ability to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon or other constituent tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. We have discharge permits in place for a number of our facilities. These permits may require us to monitor and sample the storm water runoff from such facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Underground Injection Control. Our underground injection operations are subject to the Safe Drinking Water Act, as well as analogous state laws and regulations, which establish requirements for permitting, testing, monitoring, record keeping, and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our permits, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third parties for property damages and personal injuries.

Hydraulic Fracturing. The underground injection of crude oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. We do not conduct any hydraulic fracturing activities. However, a portion of our customers' crude oil and natural gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process and our water solutions business treats and disposes of wastewater generated from natural gas production, including production utilizing hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate oil and gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of the United States Congress. Congress will likely continue to consider legislation to amend the Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under the Act's Underground Injection Control Program and/or to require disclosure of chemicals used in the hydraulic fracturing process. Federal agencies, including the EPA and the United States Department of the

Interior, have asserted their regulatory authority to, for example, study the potential impacts of hydraulic fracturing on the environment, and initiate rulemakings to compel disclosure of the chemicals used in hydraulic fracturing operations, and establish pretreatment standards for wastewater from hydraulic fracturing operations. In addition, some states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing, which include additional permit requirements, public disclosure of fracturing fluid contents, operational restrictions, and/or temporary or permanent bans on hydraulic fracturing. We expect that scrutiny of hydraulic fracturing activities will continue in the future.

Greenhouse Gas Regulation

There is a growing concern, both nationally and internationally, about climate change and the contribution of greenhouse gas emissions, most notably carbon dioxide, to global warming. In June 2009, the United States House of Representatives passed the ACES Act, also known as the Waxman-Markey Bill, but the ACES Act ultimately was not enacted

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by the 111th Congress. The ACES Act would have established an economy-wide cap on emissions of greenhouse gases in the United States and would have required most sources of greenhouse gas emissions to obtain and hold "allowances" corresponding to their annual emissions of greenhouse gases. A steady stream of legislation regarding climate change continues to be introduced into Congress, but none of the proposed bills have received bipartisan support. Recently, Rep. Chris Van Hollen (D-MD) introduced H.R. 1027, which would cap greenhouse gas emissions and require the purchase of carbon permits. The bill was referred to the Ways and Means Committee and the Energy and Commerce Committee on February 24, 2015 but has not yet advanced out of committee. The ultimate outcome of any possible future federal legislative initiatives is uncertain. In addition, several states have already adopted some legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allowed the EPA to adopt and implement regulations to restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA has issued a number of regulations addressing greenhouse gas emissions under the federal Clean Air Act, including (i) the greenhouse gas reporting rule; (ii) greenhouse gas standards applicable to heavy-duty and light-duty vehicles; and (iii) a rule requiring stationary sources to address greenhouse gas emissions in Prevention of Significant Deterioration and Title V permits, known as the Tailoring Rule. The United States Supreme Court invalidated the Tailoring Rule in Utility Air Regulatory Group v. EPA on June 23, 2014. Under the Supreme Court's decision, sources are no longer required to obtain Prevention of Significant Deterioration or Title V permits based solely on their greenhouse gas emissions; however, installation of the best available control technology for greenhouse gases may be required at sources that emit more than a de minimis amount of greenhouse gases and are otherwise required to obtain Prevention of Significant Deterioration permits. On January 14, 2015, the EPA announced its intention to propose regulations that would require reductions in methane and volatile organic compound emissions from the oil and gas industry. The schedule for when these regulations will be proposed or finalized is not presently known. The EPA's greenhouse gas regulations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations and also could adversely affect demand for the products that we transport, store, process, or otherwise handle in connection with our services.

Some scientists have suggested climate change from greenhouse gases could increase the severity of extreme weather, such as increased hurricanes and floods, which could damage our facilities. Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for our natural gas liquids is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for our products and services. If there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Because propane is considered a clean alternative fuel under the federal Clean Air Act Amendments of 1990, new climate change regulations may provide us with a competitive advantage over other sources of energy, such as fuel oil and coal.

The trend of more expansive and stringent environmental legislation and regulations, including greenhouse gas regulation, could continue, resulting in increased costs of conducting business and consequently affecting our profitability. To the extent laws are enacted or other governmental action is taken that restricts certain aspects of our business or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects could be adversely affected.

Safety and Transportation

All states in which we operate have adopted fire safety codes that regulate the storage and distribution of propane and distillates. In some states, state agencies administer these laws. In others, municipalities administer them. We conduct training programs to help ensure that our operations comply with applicable governmental regulations. With respect to general operations, each state in which we operate adopts National Fire Protection Association, Pamphlet Nos. 54 and 58, or comparable regulations, which establish rules and procedures governing the safe handling of propane, and Pamphlet Nos. 30, 30A, 31, 385, and 395 which establish rules and procedures governing the safe handling of distillates, such as fuel oil. We believe that the policies and procedures currently in effect at all of our facilities for the handling, storage and distribution of propane and distillates and related service and installation operations are consistent with industry standards and are in compliance in all material respects with applicable environmental, health and safety laws.

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With respect to the transportation of propane, distillates, crude oil, and water, we are subject to regulations promulgated under federal legislation, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002. Regulations under these statutes cover the security and transportation of hazardous materials and are administered by the United States Department of Transportation (“DOT”). Specifically, crude oil pipelines are subject to regulation by the DOT, through the Pipeline and Hazardous Materials Safety Administration (“PHMSA”), under the Hazardous Liquid Pipeline Safety Act of 1979 (“HLPSA”), which requires PHMSA to develop, prescribe, and enforce minimum federal safety standards for the storage and transportation of hazardous liquids by and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations.

The Pipeline Safety Act of 1992 added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines, established safety standards for certain “regulated gathering lines,” and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in high consequence areas (“HCAs”), defined as those areas that are unusually sensitive to environmental damage, that cross a navigable waterway, or that have a high population density. In the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006, Congress required mandatory inspections for certain United States crude oil and natural gas transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management. In January 2012, the federal government passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (the “2011 Pipeline Safety Act”). This act provides for additional regulatory oversight of the nation’s pipelines, increases the penalties for violations of pipeline safety rules, and complements the DOT’s other initiatives. The 2011 Pipeline Safety Act increases the maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm from $1 million to $2 million. In addition, this law established additional safety requirements for newly constructed pipelines. The law also provides for (i) additional pipeline damage prevention measures, (ii) allowing the Secretary of Transportation to require automatic and remote-controlled shut-off valves on new pipelines, (iii) requiring the Secretary of Transportation to evaluate the effectiveness of expanding pipeline integrity management and leak detection requirements, (iv) improving the way the DOT and pipeline operators provide information to the public and emergency responders, and (v) reforming the process by which pipeline operators notify federal, state and local officials of pipeline accidents.

Railcar Regulation

We transport a significant portion of our natural gas liquids and crude oil via rail transportation, and we own and lease a fleet of railcars for this purpose. Our railcar operations are subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, as well as other federal and state regulatory agencies.

Occupational Health Regulations

The workplaces associated with our manufacturing, processing, terminal and storage facilities are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. We believe we have conducted our operations in substantial compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances. Our marine vessel operations are also subject to safety and operational standards established and monitored by the United States Coast Guard. In general, we expect to increase our expenditures relating to compliance with likely higher industry and regulatory safety standards such as those described above. However, these expenditures cannot be accurately estimated at this time, but we do not expect them to have a material adverse effect on our business.

Available Information on our Website

Our website address is http://www.nglenergypartners.com. We make available on our website, free of charge, the periodic reports that we file with or furnish to the Securities and Exchange Commission ("SEC"), as well as all amendments to these reports, as soon as reasonably practicable after such reports are filed with or furnished to the SEC. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information about 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 related to issuers that file electronically with the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

We may not have sufficient cash to enable us to pay the minimum quarterly distribution to our unitholders following the establishment of cash reserves by our general partner and the payment of costs and expenses, including reimbursement of expenses to our general partner.

We may not have sufficient cash each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our common units principally depends on the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- weather conditions in our operating areas;
- the cost of crude oil, natural gas liquids, refined products, ethanol, and biodiesel that we buy for resale and whether we are able to pass along cost increases to our customers;
- the volume of wastewater delivered to our processing facilities;
- disruptions in the availability of crude oil and/or natural gas liquids supply;
- our ability to renew leases for storage and railcars;
- the effectiveness of our commodity price hedging strategy;
- the level of competition from other energy providers; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution also depends on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- the cost of acquisitions, if any;
- restrictions contained in our credit agreement (the “Credit Agreement”), the purchase agreement governing our outstanding 6.65% senior secured notes due 2022 (the “Note Purchase Agreement”), the indentures governing our outstanding 6.875% senior notes due 2021 and 5.125% senior notes due 2019 (collectively, the “Indentures”) and other debt service requirements;
- fluctuations in working capital needs;
- our ability to borrow funds and access capital markets;
- the amount, if any, of cash reserves established by our general partner; and
- other business risks discussed in this Annual Report that may affect our cash levels.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we realize net income.

The amount of cash we have available for distribution depends primarily on our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we might make cash distributions during periods when we record net losses for financial accounting purposes and we might not make cash distributions during periods when we record net income for financial accounting purposes.

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Our future financial performance and growth may be limited by our ability to successfully complete accretive acquisitions on economically acceptable terms.

Our ability to complete acquisitions on economically acceptable terms may be limited by various factors, including, but not limited to:

- increased competition for attractive acquisitions;
- covenants in our Credit Agreement, Note Purchase Agreement and Indentures that limit the amount and types of indebtedness that we may incur to finance acquisitions and which may adversely affect our ability to make distributions to our unitholders;
- lack of available cash or external capital or limitations on our ability to issue equity to pay for acquisitions; and
- possible unwillingness of prospective sellers to accept our common units as consideration and the potential dilutive effect to our existing unitholders caused by an issuance of common units in an acquisition.

There can be no assurance that we will identify attractive acquisition candidates in the future, that we will be able to acquire such businesses on economically favorable terms, that any acquisitions will not be dilutive to earnings and distributions or that any additional debt that we incur to finance an acquisition will not affect our ability to make distributions to unitholders. Furthermore, if we consummate any future acquisitions, our capitalization and results of operations may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

While our business strategy includes expanding our existing retail propane operations through internal growth, our ability to expand our retail propane business will primarily be dependent on our ability to successfully complete accretive acquisitions. There can be no assurances that we will be able to identify suitable acquisition candidates or successfully complete acquisitions in this line of business. The propane industry is a mature industry, and we anticipate only limited growth in total national demand for propane in the near future. Increased competition from alternative energy sources has limited growth in the propane industry, and year-to-year industry volumes are primarily impacted by fluctuations in weather and economic conditions.

We may be subject to substantial risks in connection with the integration and operation of acquired businesses, in particular those businesses with operations that are distinct and separate from our existing operations.

Any acquisitions we make in pursuit of our growth strategy are subject to potential risks, including, but not limited to:

- the inability to successfully integrate the operations of recently acquired businesses;
- the assumption of known or unknown liabilities, including environmental liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt or synergies;
- unforeseen difficulties operating in new geographic areas or in new business segments;
- the diversion of management's and employees' attention from other business concerns;
- customer or key employee loss from the acquired businesses; and
- a potential significant increase in our indebtedness and related interest expense.

We undertake due diligence efforts in our assessment of acquisitions, but may be unable to identify or fully plan for all issues and risks attendant to a particular acquisition. Even when an issue or risk is identified, we may be unable to obtain adequate contractual protection from the seller. The realization of any of these risks could have a material adverse effect on the success of a particular acquisition or our consolidated financial position, results of operations or future growth.

As part of our growth strategy, we may expand our operations into businesses that differ from our existing operations. Integration of new businesses is a complex, costly and time-consuming process and may involve assets with which we have limited operating experience. Failure to timely and successfully integrate acquired businesses into our existing operations may have a material adverse effect on our business, consolidated financial position or results of operations. In addition to the risks set forth above, new businesses will subject us to additional business and operating risks, such as the acquisitions not being accretive to our unitholders as a result of decreased profitability, increased interest expense related to debt we incur to make

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such acquisitions or an inability to successfully integrate those operations into our overall business operation. The realization of any of these risks could have a material adverse effect on our consolidated financial position or results of operations.

Our substantial indebtedness may limit our flexibility to obtain financing and to pursue other business opportunities.

At March 31, 2016, the face amount of our long-term debt was $2.9 billion. Our level of debt could have important consequences to us, including the following:

- 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;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make principal and interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend on, among other things, our future financial and operating performance, which will be affected by prevailing economic and weather conditions, and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our future indebtedness, we would be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may be unable to effect any of these actions on satisfactory terms or at all. The agreements governing our indebtedness permit us to incur additional debt under certain circumstances, and we will likely need to incur additional debt in order to implement our growth strategy. We may experience adverse consequences from increased levels of debt.

Restrictions in our Credit Agreement, Note Purchase Agreement and Indentures could adversely affect our business, financial position, results of operations, ability to make distributions to unitholders and the value of our common units.

Our Credit Agreement, Note Purchase Agreement and Indentures limit our ability to, among other things:

- incur additional debt or issue letters of credit;
- redeem or repurchase units;
- make certain loans, investments and acquisitions;
- incur certain liens or permit them to exist;
- engage in sale and leaseback transactions;
- enter into certain types of transactions with affiliates;
- enter into agreements limiting subsidiary distributions;
- change the nature of our business or enter into a substantially different business;
- merge or consolidate with another company; and
- transfer or otherwise dispose of assets.

We are permitted to make distributions to our unitholders under our Credit Agreement, Note Purchase Agreement and Indentures as long as no default or event of default exists both immediately before and after giving effect to the declaration and payment of the distribution and the distribution does not exceed available cash for the applicable quarterly period. Our Credit Agreement, Note Purchase Agreement and Indentures also contain covenants requiring us to maintain certain financial ratios. Please see Note 8 to our consolidated financial statements included in this Annual Report.

The provisions of our Credit Agreement, Note Purchase Agreement and Indentures may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our Credit Agreement could result in a covenant violation, default or an event of default that could enable our lenders, subject to the terms and conditions of our Credit Agreement, to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If we were unable to repay the accelerated amounts, our lenders could proceed against the collateral we granted them to secure our debts. If the payment of our debt is accelerated, defaults under our other debt instruments, if any then exist, may be triggered, and our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

Increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes, and our ability to make cash distributions at our intended levels.

Interest rates may increase in the future. As a result, interest rates on our existing and future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price will be impacted by our level of cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue equity or incur debt for acquisitions or other purposes and to make payments on our debt obligations and cash distributions at our intended levels.

Our business depends on the availability of supply of crude oil, natural gas liquids, and refined products in the United States and Canada, which is dependent on the ability and willingness of other parties to explore for and produce crude oil and natural gas. Spending on crude oil and natural gas exploration and production may be adversely affected by industry and financial market conditions that are beyond our control including, without limitation, (1) prices for crude oil, condensate, and natural gas liquids, (2) crude oil and natural gas producers having success in their operations, (3) continued commercially viable areas in which to explore and produce crude oil and natural gas, (4) the availability of liquids-rich natural gas needed to produce natural gas liquids, and (5) the availability of pipeline transportation and storage capacity.

Our business depends on domestic spending by the oil and natural gas industry, and this spending and our business have been, and may continue to be, adversely affected by industry and financial market conditions and existing or new regulations, such as those related to environmental matters, that are beyond our control.

We depend on the ability and willingness of other entities to make operating and capital expenditures to explore for, develop, and produce crude oil and natural gas in the United States and Canada, and to extract natural gas liquids from natural gas as well as the availability of necessary pipeline transportation and storage capacity. Customers' expectations of lower market prices for crude oil and natural gas, as well as the availability of capital for operating and capital expenditures, may cause them to curtail spending, thereby reducing business opportunities and demand for our services and equipment. Actual market conditions and producers' expectations of market conditions for crude oil, condensate and natural gas liquids may also cause producers to curtail spending, thereby reducing business opportunities and demand for our services.

Industry conditions are influenced by numerous factors over which we have no control, such as the availability of commercially viable geographic areas in which to explore and produce crude oil and natural gas, the availability of liquids-rich natural gas needed to produce natural gas liquids, the supply of and demand for crude oil and natural gas, environmental restrictions on the exploration and production of crude oil and natural gas, such as existing and proposed regulation of hydraulic fracturing, domestic and worldwide economic conditions, political instability in crude oil and natural gas producing countries and merger and divestiture activity among our current or potential customers. The volatility of the oil and natural gas industry and the resulting impact on exploration and production activity could adversely impact the level of drilling activity. This reduction may cause a decline in business opportunities or the demand for our services, or adversely affect the price of our services. Reduced discovery rates of new crude oil and natural gas reserves in our market areas also may have a negative long-term impact on our business, even in an environment of stronger crude oil and natural gas prices, to the extent existing production is not replaced.

The crude oil and natural gas production industry tends to run in cycles and may, at any time, cycle into a downturn; if that occurs, the rate at which it returns to former levels, if ever, will be uncertain. Prior adverse changes in the global economic environment and capital markets and declines in prices for crude oil and natural gas have caused many customers to reduce capital budgets for future periods and have caused decreased demand for crude oil and natural gas. Limitations on the availability of capital, or higher costs of capital, for financing expenditures have caused and may continue to cause customers to make additional reductions to capital budgets in the future even if commodity prices increase from current levels. These cuts in spending may curtail drilling programs and other discretionary spending, which could result in a reduction in business opportunities and demand for our services, the rates we can charge and our utilization. In addition, certain of our customers could become unable to pay their suppliers, including us. Any of these conditions or events could materially and adversely affect our consolidated results of operations.

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Declining crude oil prices could adversely impact our water solutions and crude oil logistics businesses.

Crude oil spot and forward prices experienced a sharp decline during the second half of calendar year 2014. During calendar year 2015, crude oil prices remained low and trended down during the second half of the year and into the first quarter of calendar year 2016. This had an unfavorable impact on the revenues of our water solutions business. The volume of water we process is driven in part by the level of crude oil production, and the lower crude oil prices have given producers less incentive to expand production. In addition, a portion of the revenues of our water solutions business is generated from the sale of hydrocarbons that we recover when processing wastewater, and lower crude oil prices have an adverse impact on these revenues. A further decline in crude oil prices or a prolonged period of low crude oil prices could have an adverse effect on our water solutions business.

In addition, the sharp decline in crude oil prices has reduced the incentive for producers to expand production. If crude oil prices remain low, resultant declines in crude oil production could adversely impact volumes in our crude oil logistics business.

Our profitability could be negatively impacted by price and inventory risk related to our business.

The crude oil logistics, liquids, retail propane, refined products, and renewables businesses are “margin-based” businesses in which our realized margins depend on the differential of sales prices over our total supply costs. Our profitability is therefore sensitive to changes in product prices caused by changes in supply, pipeline transportation and storage capacity or other market conditions.

Generally, we attempt to maintain an inventory position that is substantially balanced between our purchases and sales, including our future delivery obligations. We attempt to obtain a certain margin for our purchases by selling our product to our customers, which include third-party consumers, other wholesalers and retailers, and others. However, market, weather or other conditions beyond our control may disrupt our expected supply of product, and we may be required to obtain supply at increased prices that cannot be passed through to our customers. In general, product supply contracts permit suppliers to charge posted prices at the time of delivery or the current prices established at major storage points, creating the potential for sudden and drastic price fluctuations. Sudden and extended wholesale price increases could reduce our margins and could, if continued over an extended period of time, reduce demand by encouraging retail customers to conserve or convert to alternative energy sources. Conversely, a prolonged decline in product prices could potentially result in a reduction of the borrowing base under our working capital facility, and we could be required to liquidate inventory that we have already presold.

One of the strategies of our refined products and renewables segment is to purchase refined products in the Gulf Coast region and to transport the product on the Colonial pipeline for sale in the Southeast and East Coast. Spreads between product prices in the Gulf Coast compared to locations along the Colonial pipeline can vary significantly, which can create volatility in our product margins. In addition, we are subject to the risk of a price decline between the time we purchase refined products and the time we sell the products. We seek to mitigate this risk by entering into NYMEX futures contracts. However, price changes in locations where we operate do not correspond directly with changes in prices in the NYMEX futures market, and as a result these futures contracts cannot be perfect hedges of our commodity price risk.

We are affected by competition from other midstream, transportation, terminaling and storage, and retail-marketing companies, some of which are larger and more firmly established and may have greater marketing and development budgets and capital resources than we do.

We experience competition in all of our segments. In our liquids segment, we compete for natural gas supplies and also for customers for our services. Our competitors include major integrated oil companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store and market natural gas. Our natural gas liquids terminals compete with other terminaling and storage providers in the transportation and storage of natural gas liquids. Natural gas and natural gas liquids also compete with other forms of energy, including electricity, coal, fuel oil and renewable or alternative energy.

Our crude oil logistics segment faces significant competition for crude oil supplies and also for customers for our services. These operations also face competition from trucks for incremental and marginal volumes in the areas we serve. Further, our crude oil terminals compete with terminals owned by integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

Our water solutions segment is in direct and indirect competition with other businesses, including disposal and other wastewater treatment businesses.

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We face strong competition in the market for the sale of retail propane and distillates. Our competitors vary from retail propane companies who are larger and have substantially greater financial resources than we do to small retail propane distributors, rural electric cooperatives and fuel oil distributors who have entered the market due to a low barrier to entry. The actions of our retail-marketing competitors, including the impact of imports, could lead to lower prices or reduced margins for the products we sell, which could have an adverse effect on our business or consolidated results of operations.

Our refined products and renewables segment also faces significant competition for refined products and renewables supplies and also for customers for our services.

We can make no assurances that we will be able to compete successfully in each of our lines of business. If a competitor attempts to increase market share by reducing prices, we may lose customers, which would reduce our revenues.

Our business would be adversely affected if service at our principal storage facilities or on the common carrier pipelines we use is interrupted.

We use third-party common carrier pipelines to transport and we use third-party facilities to store our products. Any significant interruption in the service at these storage facilities or on the common carrier pipelines we use would adversely affect our ability to obtain products.

Our business would be adversely affected if service on the railroads we use is interrupted.

We transport crude oil, natural gas liquids, ethanol, and biodiesel by railcar. We do not own or operate the railroads on which these railcars are transported. Any disruptions in the operations of these railroads could adversely impact our ability to deliver product to our customers.

If we are unable to purchase product from our principal suppliers, our results of operations would be adversely affected.

If we are unable to purchase product from significant suppliers, our failure to obtain alternate sources of supply at competitive prices and on a timely basis would adversely affect our ability to satisfy customer demand, reduce our revenues and adversely affect our consolidated results of operations.

The fees charged to customers under our agreements with them for the transportation and marketing of crude oil, condensate, natural gas liquids, refined products, ethanol, and biodiesel may not escalate sufficiently to cover increases in costs and the agreements may be suspended in some circumstances, which would affect our profitability.

Our costs may increase at a rate greater than the rate that the fees that we charge to customers increase pursuant to our contracts with them. Additionally, some customers' obligations under their agreements with us may be permanently or temporarily reduced upon the occurrence of certain events, some of which are beyond our control, including force majeure events wherein the supply of crude oil, condensate, and/or natural gas liquids are curtailed or cut off. Force majeure events include (but are not limited to) revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, acts of God, explosions, mechanical or physical failures of our equipment or facilities of our customers. If the escalation of fees is insufficient to cover increased costs or if any customer suspends or terminates its contracts with us, our profitability could be materially and adversely affected.

Our sales of crude oil, condensate, natural gas liquids, refined products, ethanol, and biodiesel and related transportation and hedging activities, and our processing of wastewater, expose us to potential regulatory risks.

The FTC, the FERC, and the CFTC hold statutory authority to monitor certain segments of the physical and financial energy commodity markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of energy commodities, and any related transportation and/or hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Additionally, to the extent that we enter into transportation contracts with pipelines that are subject to the FERC regulation or we become subject to the FERC regulation ourselves (see "–Some of our operations could be subject to the jurisdiction of the FERC in the future," below), we will be obligated to comply with the FERC's regulations and policies. Any failure on our part to comply with the FERC's regulations and policies at that time could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material and adverse effect on our business, consolidated results of operations and financial position.

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The intrastate transportation or storage of crude oil and refined products is subject to regulation by the state in which the facilities and transactions occur and requires compliance with all such regulation. These state regulations can have a material and adverse effect on that portion of our business, consolidated results of operations and financial position.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) provides for statutory and regulatory requirements for derivative transactions, including crude oil and natural gas hedging transactions. Certain transactions will be required to be cleared on exchanges and cash collateral will have to be posted. The Dodd-Frank Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end users and it includes a number of defined terms that will be used in determining how this exemption applies to particular derivative transactions and the parties to those transactions. Since the Dodd-Frank Act mandates the CFTC to promulgate rules to define these terms, the full impact of the Dodd-Frank Act on our hedging activities is uncertain at this time. However, new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. The Dodd-Frank Act may also materially affect our customers and materially and adversely affect the demand for our services.

We are subject to trucking safety regulations, which are enacted, reviewed and amended by the Federal Motor Carrier Safety Administration (“FMCSA”). If our current DOT safety ratings are downgraded to “Unsatisfactory”, our business and results of our operations may be adversely affected.

All federally regulated carriers’ safety ratings are measured through a program implemented by the FMCSA known as the Compliance Safety Accountability (“CSA”) program. The CSA program measures a carrier’s safety performance based on violations observed during roadside inspections as opposed to compliance audits performed by the FMCSA. The quantity and severity of any violations are compared to a peer group of companies of comparable size and annual mileage. If a company rises above a threshold established by the FMCSA, it is subject to action from the FMCSA. There is a progressive intervention strategy that begins with a company providing the FMCSA with an acceptable plan of corrective action that the company will implement. If the issues are not corrected, the intervention escalates to on-site compliance audits and ultimately an “unsatisfactory” rating and the revocation of the company’s operating authority by the FMCSA, which could result in a material adverse effect on our business, consolidated results of operations and financial position and ability to make cash distributions to our unitholders.

Our business is subject to federal, state, provincial and local laws and regulations with respect to environmental, safety and other regulatory matters and the cost of compliance with, violation of or liabilities under, such laws and regulations could adversely affect our profitability.

Our operations, including those involving crude oil, condensate, natural gas liquids, refined products, renewables, and crude oil and natural gas produced wastewater, are subject to stringent federal, state, provincial and local laws and regulations relating to the protection of natural resources and the environment, health and safety, waste management, and transportation and disposal of such products and materials. We face inherent risks of incurring significant environmental costs and liabilities in the performance of our operations due to handling of wastewater and hydrocarbons, such as crude oil, condensate, natural gas liquids, refined products, ethanol, and biodiesel. For instance, our water solutions business carries with it environmental risks, including leakage from the treatment plants to surface or subsurface soils, surface water or groundwater, or accidental spills. Our crude oil logistics, liquids, and refined products and renewables businesses carry similar risks of leakage and sudden or accidental spills of crude oil, natural gas liquids, and hydrocarbons. Liability under, or violation of, environmental laws and regulations could result in, among other things, the impairment or cancellation of operations, injunctions, fines and penalties, reputational damage, expenditures for remediation and liability for natural resource damages, property damage and personal injuries.

We use various modes of transportation to carry propane, distillates, crude oil and water, including trucks, railcars and barges, each of which is subject to regulation. With respect to transportation by truck, we are subject to regulations promulgated under federal legislation, including the Federal Motor Carrier Safety Act and the Homeland Security Act of 2002, which cover the security and transportation of hazardous materials and are administered by the DOT. We also own and lease a fleet of railcars, the operation of which is subject to the regulatory jurisdiction of the Federal Railroad Administration of the DOT, as well as other federal and state regulatory agencies. Recent railcar accidents within the industry in Quebec, Alabama, North Dakota, Pennsylvania and Virginia, in each case involving trains carrying crude oil from the Bakken region (none of which directly involved any of our business operations), have led to increased legislative and regulatory scrutiny over the safety of transporting crude oil by railcar. In 2015, the DOT, through the PHMSA, issued a rule implementing new railcar standards and railroad operating procedures. The introduction of these or other regulations that result in new requirements addressing the type, design, specifications or construction of railcars used to transport crude oil could result in severe transportation capacity constraints during the period in which new railcars are retrofitted or constructed to meet new specifications. Our barge transportation operations are subject to the Jones Act, a federal law restricting marine transportation in the United States to vessels built and registered in the United States, and manned and owned by United States citizens, as well as rules and regulations of the United States Coast Guard. Non-compliance with any of these regulations could result in increased costs related to the transportation of our products and could have an adverse effect on our business.

In addition, under certain environmental laws, we could be subject to strict and/or joint and several liability for the investigation, removal or remediation of previously released materials. As a result, these laws could cause us to become liable for the conduct of others, such as prior owners or operators of our facilities, or for consequences of our or our predecessor’s actions, regardless of whether we were responsible for the release or if such actions were in compliance with all applicable laws at the time of those actions. Also, upon closure of certain facilities, such as at the end of their useful life, we have been and may be required to undertake environmental evaluations or cleanups.

Additionally, in order to conduct our operations, we must obtain and maintain numerous permits, approvals and other authorizations from various federal, state, provincial and local governmental authorities relating to wastewater handling, discharge and disposal, air emissions, transportation and other environmental matters. These authorizations subject us to terms and conditions which may be onerous or costly to comply with, and that may require costly operational modifications to attain and maintain compliance. The renewal, amendment or modification of these permits, approvals and other authorizations may involve the imposition of even more stringent and burdensome terms and conditions with attendant higher costs and more significant effects upon our operations.

Changes in environmental laws and regulations occur frequently. New laws or regulations, changes to existing laws or regulations, such as more stringent pollution control requirements or additional safety requirements, or more stringent interpretation or enforcement of existing laws and regulations, may adversely impact us, and could result in increased operating costs and have a material and adverse effect on our activities and profitability. For example, new or proposed laws or regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our costs for treatment of hydraulic fracturing flowback water (or affect our hydraulic fracturing customers’ ability to operate) and cause delays, interruption or termination of our water treatment operations, all of which could have a material and adverse effect on our consolidated results of operations and financial position.

Furthermore, our customers in the oil and gas production industry are subject to certain environmental laws and regulations that may impose significant costs and liabilities on them, including as a result of changes in such laws and regulations causing them to become more stringent over time. For example, in April 2012, the EPA issued final rules that established new air emission controls for crude oil and natural gas production and gas processing operations. The final rule includes a 95% reduction in volatile organic compounds (“VOCs”) (which contribute to smog) emitted during the completion of new and modified hydraulically fractured wells. In August 2013, the EPA updated its 2012 air emission standards for crude oil and natural gas storage tanks to extend the compliance date and allow an alternate emissions limit of less than four tons per year without emission controls. On September 18, 2015, the EPA proposed new source performance standards for the oil and gas sector, which would require reductions in methane and VOC emissions across the oil and gas industry if finalized. The schedule for when these regulations will be proposed or finalized is not presently known, although the EPA has indicated its intention to finalize the regulations by the end of calendar year 2016. Any significant increased costs or restrictions placed on our customers to comply with environmental laws and regulations could affect their production output significantly. Such an effect could materially and adversely affect our utilization and profitability, thus reducing demand for our midstream services. Such an effect on our customers could materially and adversely affect our utilization and profitability. The adoption or implementation of any new regulations imposing additional reporting obligations on greenhouse gas emissions, or limiting greenhouse gas emissions from our equipment and operations, could require us to incur significant costs.

Federal and state legislation and regulatory initiatives relating to our hydraulic fracturing customers could result in increased costs and additional operating restrictions or delays and could harm our business.

Hydraulic fracturing is a frequent practice in the crude oil and natural gas fields in which our water solutions segment operates. Hydraulic fracturing is an important and common process used to facilitate production of natural gas and other hydrocarbon condensates in shale formations, as well as tight conventional formations. The hydraulic fracturing process is primarily regulated by state oil and gas authorities. This process has come under considerable scrutiny from sections of the public as well as environmental and other groups asserting that chemicals used in the hydraulic fracturing process could adversely affect drinking water supplies. New laws or regulations, or changes to existing laws or regulations in response to this perceived threat may adversely impact the oil and gas drilling industry. For instance, the EPA has asserted federal regulatory

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authority over certain hydraulic fracturing practices involving the use of diesel fuel under the Safe Drinking Water Act and its Underground Injection Control program. In February 2014, the EPA issued technical guidance for the permitting of the underground injection of diesel fuel for hydraulic fracturing activities. At the request of the United States Congress, the EPA is undertaking a study of the impact of hydraulic fracturing on drinking water resources. In June 2015, the EPA released its draft assessment, which found that although hydraulic fracturing activities have the potential to impact drinking water resources, there is no evidence that hydraulic fracturing has led to widespread, systemic impacts on drinking water resources in the United States. In addition, the United States Department of the Interior issued a final rule on March 20, 2015 updating existing regulation of hydraulic fracturing activities on federal and tribal lands, including requirements for disclosure of chemicals used in hydraulic fracturing to the Bureau of Land Management, well bore integrity and handling of flowback water. Also, legislation has been introduced, but not adopted, in Congress to provide for federal regulation of hydraulic fracturing. In addition, some states have adopted and other states are considering adopting regulations that could restrict or regulate hydraulic fracturing in certain circumstances. For example, some states have adopted legislation requiring the disclosure of hydraulic fracturing chemicals, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the hydraulic fracturing process could adversely affect groundwater. Other states, such as New York, have banned hydraulic fracturing. We cannot predict whether any proposed federal, state or local laws or regulations will be enacted and, if so, what actions any such laws or regulations would require or prohibit. However, any restrictions on hydraulic fracturing could lead to operational delays or increased operating costs and regulatory burdens that could make it more difficult or costly to perform hydraulic fracturing which would negatively impact our customer base resulting in an adverse effect on our profitability.

Federal and state legislation and regulatory initiatives relating to saltwater disposal wells could result in increased costs and additional operating restrictions or delays and could harm our business.

The water disposal process is primarily regulated by state oil and gas authorities. This water disposal process has come under considerable scrutiny from sections of the public as well as environmental and other groups asserting that the operation of certain water disposal wells has caused increased seismic activity. New laws or regulations, or changes to existing laws or regulations, in response to this perceived threat may adversely impact the water disposal industry.

On certain occasions, a state regulatory agency has requested that we suspend operations at a specified disposal facility, pending further study of its potential impact on seismic activity. In one instance we have modified a disposal well to redirect the flow of water to a different area of the geologic formation in order to address such concerns.

We cannot predict whether any federal, state or local laws or regulations will be enacted and, if so, what actions any such laws or regulations would require or prohibit. However, any restrictions on water disposal could lead to operational delays or increased operating costs and regulatory burdens that could make it more difficult or costly to perform water disposal operations, which would negatively impact our profitability.

Seasonal weather conditions and natural or man-made disasters could severely disrupt normal operations and have an adverse effect on our business, financial position and results of operations.

We operate in various locations across the United States and Canada which may be adversely affected by seasonal weather conditions and natural or man-made disasters. During periods of heavy snow, ice, rain or extreme weather conditions such as high winds, tornados and hurricanes or after other natural disasters such as earthquakes or wildfires, we may be unable to move our trucks or railcars between locations and our facilities may be damaged, thereby reducing our ability to provide services and generate revenues. In addition, hurricanes or other severe weather in the Gulf Coast region could seriously disrupt the supply of products and cause serious shortages in various areas, including the areas in which we operate. These same conditions may cause serious damage or destruction to homes, business structures and the operations of customers. Such disruptions could potentially have a material adverse impact on our business, consolidated financial position, results of operations and cash flows.

Risk management procedures cannot eliminate all commodity risk, basis risk, or risk of adverse market conditions which can adversely affect our financial position and results of operations. In addition, any non-compliance with our risk policy could result in significant financial losses.

Pursuant to the requirements of our market risk policy, we attempt to lock in a margin for a portion of the commodities we purchase by selling such commodities for physical delivery to our customers, such as independent refiners or major oil companies, or by entering into future delivery obligations under contracts for forward sale. We also enter into financial derivative contracts, such as futures, to manage commodity price risk. Through these transactions, we seek to maintain a position that is substantially balanced between purchases on the one hand, and sales or future delivery obligations on the other

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hand. These policies and practices cannot, however, eliminate all risks. For example, any event that disrupts our anticipated physical supply of commodities could expose us to risk of loss resulting from the need to cover obligations required under contracts for forward sale. Additionally, we can provide no assurance that our processes and procedures will detect and/or prevent all violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

Basis risk describes the inherent market price risk created when a commodity of certain grade or location is purchased, sold or exchanged as compared to a purchase, sale or exchange of a like commodity at a different time or place. Transportation costs and timing differentials are components of basis risk. In a backwardated market (when prices for future deliveries are lower than current prices), basis risk is created with respect to timing. In these instances, physical inventory generally loses value as price of such physical inventory declines over time. Basis risk cannot be entirely eliminated, and basis exposure, particularly in backwardated or other adverse market conditions, can adversely affect our consolidated financial position and results of operations.

The counterparties to our commodity derivative and physical purchase and sale contracts may not be able to perform their obligations to us, which could materially affect our cash flows and results of operations.

We encounter risk of counterparty nonperformance in our businesses. Disruptions in the supply of product and in the crude oil and natural gas commodities sector overall for an extended or near term period of time could result in counterparty defaults on our derivative and physical purchase and sale contracts. This could impair our ability to obtain supply to fulfill our sales delivery commitments or obtain supply at reasonable prices, which could result in decreased gross margins and profitability, thereby impairing our ability to make payments on our debt obligations or distributions to our unitholders.

Our use of derivative financial instruments could have an adverse effect on our results of operations.

We have used derivative financial instruments as a means to protect against commodity price risk or interest rate risk and expect to continue to do so. We may, as a component of our overall business strategy, increase or decrease from time to time our use of such derivative financial instruments in the future. Our use of such derivative financial instruments could cause us to forego the economic benefits we would otherwise realize if commodity prices or interest rates were to change in our favor. In addition, although we monitor such activities in our risk management processes and procedures, such activities could result in losses, which could adversely affect our consolidated results of operations and impair our ability to make payments on our debt obligations or distributions to our unitholders.

Some of our operations could be subject to the jurisdiction of the FERC in the future.

The Joint Pipeline currently under construction by Grand Mesa and Saddlehorn will have several points of origin in Colorado and will terminate in Cushing, Oklahoma. The transportation services on this pipeline will be subject to FERC regulation once the pipeline commences service. Any of our transportation services could in the future become subject to the jurisdiction of the FERC, which could adversely affect the terms of service, rates and revenues of such services. At the date of this Annual Report, our facilities do not fall under the FERC's jurisdiction. Currently, the FERC regulates the transportation of crude oil and refined products on interstate pipelines, among other things. Intrastate transportation and gathering pipelines that do not provide interstate services are not subject to regulation by the FERC. However, the distinction between the FERC-regulated interstate pipeline transportation on the one hand and intrastate pipeline transportation on the other hand, is a fact-based determination.

The classification and regulation of our crude oil pipelines are subject to change based on future determinations by the FERC, federal courts, Congress or regulatory commissions, courts or legislatures in the states in which we operate. Glass Mountain, one of our joint ventures, owns a pipeline in Oklahoma that carries crude oil owned by us and by third parties. We believe that the pipeline segments on which Glass Mountain would provide service to third parties and the services it would provide to third parties on this pipeline system meet the traditional tests that the FERC has used to determine that the pipeline services provided are not in interstate commerce. However, we cannot provide assurance that the FERC will not in the future, either at the request of other entities or on its own initiative, determine that some or all of the pipeline and the services Glass Mountain will provide on that system are within its jurisdiction, or that such a determination would not adversely affect Glass Mountain's or our consolidated results of operations. If the FERC's regulatory reach was expanded to our other facilities, or if we expand our operations into areas that are subject to the FERC's regulation, we may have to commit substantial capital to comply with such regulations and such expenditures could have a material and adverse effect on our consolidated results of operations and cash flows.

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Volumes of crude oil recovered during the wastewater treatment process can vary. Any significant reduction in residual crude oil content in wastewater we treat will affect our recovery of crude oil and, therefore, our profitability.

A portion of revenues in our water solutions business is generated from the sale of hydrocarbons that we recover when processing wastewater. Our ability to recover sufficient volumes of hydrocarbons is dependent upon the residual crude oil content in the wastewater we treat, which is, among other things, a function of water temperature. Generally, where water temperature is higher, residual crude oil content is lower. Thus, our crude oil recovery during the winter season is substantially higher than our recovery during the summer season. Additionally, residual crude oil content will decrease if, among other things, producers begin recovering higher levels of crude oil in produced wastewater prior to delivering such water to us for treatment. Any reduction in residual crude oil content in the wastewater we treat could materially and adversely affect our profitability.

Competition from alternative energy sources may cause us to lose customers, thereby negatively impacting our financial position and results of operations.

Propane competes with other sources of energy, some of which are less costly for equivalent energy value. We compete for customers against suppliers of electricity, natural gas and fuel oil. Competition from alternative energy sources, including electricity and natural gas, has increased as a result of reduced regulation of many utilities. Electricity is a major competitor of propane, but propane has historically enjoyed a competitive price advantage over electricity. Except for some industrial and commercial applications, propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because such pipelines generally make it possible for the delivered cost of natural gas to be less expensive than the bulk delivery of propane. The expansion of natural gas into traditional propane markets has historically been inhibited by the capital cost required to expand distribution and pipeline systems; however, the gradual expansion of the nation’s natural gas distribution systems has resulted in natural gas being available in areas that previously depended on propane, which could cause us to lose customers, thereby reducing our revenues. Although propane is similar to fuel oil in some applications and market demand, propane and fuel oil compete to a lesser extent primarily because of the cost of converting from one to the other and due to the fact that both fuel oil and propane have generally developed their own distinct geographic markets.

We cannot predict the effect that development of alternative energy sources may have on our operations, including whether subsidies of alternative energy sources by local, state, and federal governments might be expanded, or what impact this might have on the supply of or the demand for crude oil, natural gas, and natural gas liquids.

Energy efficiency and new technology may reduce the demand for propane and adversely affect our operating results.

The national trend toward increased conservation and technological advances, such as installation of improved insulation and the development of more efficient furnaces and other heating devices, has adversely affected the demand for propane by retail customers. Future conservation measures or technological advances in heating, conservation, energy generation or other devices may reduce demand for propane. In addition, if the price of propane increases, some of our customers may increase their conservation efforts and thereby decrease their consumption of propane.

The majority of our retail propane operations are concentrated in the Northeast, Southeast, and Midwest, and localized warmer weather and/or economic downturns may adversely affect demand for propane in those regions, thereby affecting our financial position and results of operations.

A substantial portion of our retail propane sales are to residential customers located in the Northeast, Southeast, and Midwest who rely heavily on propane for heating purposes. A significant percentage of our retail propane volume is attributable to sales during the peak heating season of October through March. Warmer weather may result in reduced sales volumes that could adversely impact our consolidated results of operations and financial position. In addition, adverse economic conditions in areas where our retail propane operations are concentrated may cause our residential customers to reduce their use of propane regardless of weather conditions. Localized warmer weather and/or economic downturns may have a significantly greater impact on our consolidated results of operations and financial position than if our retail propane business were less concentrated.

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Reduced demand for refined products could have an adverse effect our results of operations.

Any sustained decrease in demand for refined products in the markets we serve could reduce our cash flow. Factors that could lead to a decrease in market demand include:

- a recession or other adverse economic condition that results in lower spending by consumers on gasoline, diesel, and travel;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline;
- an increase in automotive engine fuel economy, whether as a result of a shift by consumers to more fuel-efficient vehicles or technological advances by manufacturers;
- an increase in the market price of crude oil that leads to higher refined product prices, which may reduce demand for refined products and drive demand for alternative products; and
- the increased use of alternative fuel sources, such as battery-powered engines.

Recent attempts to reduce or eliminate the federal Renewable Fuels Standard ("RFS"), if successful, could adversely impact our results of operations.

The United States renewables industry is highly dependent on several federal and state incentives which promote the use of renewable fuels. Without these incentives, demand for and the price of renewable fuels could be negatively impacted which could have an adverse effect on our consolidated results of operations. The most significant of the federal and state incentives which benefit renewable products we market, such as ethanol and biodiesel, is the RFS. The RFS requires that an increasing amount of renewable fuels must be blended with petroleum-based fuels each year in the United States. However, the EPA has authority to waive the requirements of the RFS, in whole or in part, provided one of two conditions is met. The conditions are: (1) there is inadequate domestic renewable fuel supply; or (2) implementation of the requirement would severely harm the economy or environment of a state, region or the United States. Opponents of the RFS are seeking to force the EPA to reduce or eliminate the RFS. Further, several pieces of legislation have been introduced with the goal of significantly reducing or eliminating the RFS. While the outcome of these legislative efforts is uncertain, it is possible that the EPA could adjust the RFS requirements in the future. If the EPA were to adjust the RFS requirements in any material way, it could negatively impact demand for the renewable fuel products we market, which could adversely impact our consolidated results of operations.

The expiration of tax credits could adversely impact the demand for biodiesel, which could adversely impact our results of operations

The demand for biodiesel is supported by certain federal tax credits. These tax credits have typically been granted for short durations, and on several occasions these tax credits have expired. In December 2014, the federal government passed a law reinstating the tax credit retroactively to January 1, 2014 to be effective through December 31, 2014. In December 2015, the federal government re-signed the law reinstating the tax credit retroactively to January 1, 2015 to be effective through December 31, 2016. Currently no such tax credit exists for transactions subsequent to December 31, 2016, and there can be no assurance that the federal government will grant such tax credits in the future. If the federal government were to discontinue the practice of granting such tax credits, this would likely have an adverse effect on demand for biodiesel and on our biodiesel marketing operations.

A loss of one or more significant customers could materially or adversely affect our results of operations.

During the year ended March 31, 2016, 65% of the revenues of our crude oil logistics segment were generated from our ten largest customers of the segment. During the year ended March 31, 2016, 23% of the water treatment and disposal revenues of our water solutions segment were generated from our two largest customers of the segment. During the year ended March 31, 2016, 34% of the revenues of our liquids segment were generated from our ten largest customers of the segment (exclusive of sales to our retail propane segment). During the year ended March 31, 2016, 34% of the revenues of our refined products and renewables segment were generated from our ten largest customers of the segment. We expect to continue to depend on key customers to support our revenues for the foreseeable future. The loss of key customers, failure to renew contracts upon expiration, or a sustained decrease in demand by key customers could result in a substantial loss of revenues and could have a material and adverse effect on our consolidated results of operations.

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Certain of our operations are conducted through joint ventures which have unique risks.

Certain of our operations are conducted through joint ventures. With respect to our joint ventures, we share ownership and management responsibilities with partners that may not share our goals and objectives. Differences in views among the partners may result in delayed decisions or failures to agree on major matters, such as large expenditures or contractual commitments, the construction or acquisition of assets or borrowing money, among others. Delay or failure to agree may prevent action with respect to such matters, even though such action may serve our best interest or that of the joint venture. Accordingly, delayed decisions and disagreements could adversely affect the business and operations of the joint ventures and, in turn, our business and operations. From time to time, our joint ventures may be involved in disputes or legal proceedings which may negatively affect our investments. Accordingly, any such occurrences could adversely affect our consolidated results of operations, financial position and cash flows.

Growing our business by constructing new transportation systems and facilities subjects us to construction risks and risks that supplies for such systems and facilities will not be available upon completion thereof.

One of the ways we intend to grow our business is through the construction of additions to our systems and/or the construction of new terminaling, transportation, and wastewater treatment facilities. The Joint Pipeline currently under construction by Grand Mesa and Saddlehorn will have several points of origin in Colorado and will terminate in Cushing, Oklahoma; and we expect that the transportation services on this pipeline to commence beginning in the third quarter of fiscal year 2017. These expansion projects require the expenditure of significant amounts of capital, which may exceed our resources, and involves numerous regulatory, environmental, political and legal uncertainties. There can be no assurances that we will be able to complete these projects on schedule or at all or at the budgeted cost. Our revenues may not increase upon the expenditure of funds on a particular project. Moreover, we may undertake expansion projects to capture anticipated future growth in production in a region in which anticipated production growth does not materialize or for which we are unable to acquire new customers. We may also rely on estimates of proved, probable or possible reserves in our decision to undertake expansion projects, which may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of proved, probable or possible reserves. As a result, our new facilities and infrastructure may not be able to attract enough product to achieve our expected investment return, which could materially and adversely affect our consolidated results of operations and financial position.

Product liability claims and litigation could adversely affect our business and results of operations.

Our operations are subject to all operating hazards and risks incident to handling, storing, transporting and providing customers with combustible liquids. As a result, we are subject to product liability claims and lawsuits, including potential class actions, in the ordinary course of business. Any product liability claim brought against us, with or without merit, could be costly to defend and could result in an increase of our insurance premiums. Some claims brought against us might not be covered by our insurance policies. In addition, we have self-insured retention amounts which we would have to pay in full before obtaining any insurance proceeds to satisfy a judgment or settlement and we may have insufficient reserves on our balance sheet to satisfy such self-retention obligations. Furthermore, even where the claim is covered by our insurance, our insurance coverage might be inadequate and we would have to pay the amount of any settlement or judgment that is in excess of our policy limits. We may not be able to obtain insurance on terms acceptable to us or at all since insurance varies in cost and can be difficult to obtain. Our failure to maintain adequate insurance coverage or successfully defend against product liability claims could materially and adversely affect our business, consolidated results of operations, financial position and cash flows.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may affect adversely our financial results.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. If any of our financial, operational, or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk related to operational system flaws, and employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operations sectors, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse effect on our business. In addition, cyber attacks on our customer and employee data may result in a financial loss, including potential fines for failure to safeguard data, and may negatively impact our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage or otherwise have an adverse effect on our financial results.

We do not own all of the land on which our facilities are located, and instead lease certain facilities and equipment, and we, therefore, are subject to the possibility of increased costs to retain necessary land and equipment use which could disrupt our operations.

We do not own all of the land on which our facilities are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if our facilities are not properly located within the boundaries of such rights-of-way. Additionally, our loss of rights, through our inability to renew right-of-way contracts or otherwise, could materially and adversely affect our business, consolidated results of operations and financial position.

Additionally, certain facilities and equipment (or parts thereof) used by us are leased from third parties for specific periods, including many of our railcars. Our inability to renew facility or equipment leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material and adverse effect on our consolidated results of operations and cash flows.

We also must operate within the terms and conditions of permits and various rules and regulations from the United States Bureau of Land Management for the rights of way on which our pipelines are constructed and the Wyoming State Engineer’s Office for water well, disposal well and containment pits.

Difficulty in attracting and retaining qualified drivers could adversely affect our growth and profitability.

Maintaining a staff of qualified truck drivers is critical to the success of our crude oil logistics and retail propane operations. We have in the past experienced difficulty in attracting and retaining sufficient numbers of qualified drivers. Regulatory requirements, including the FMCSA’s CSA initiative, and an improvement in the economy could reduce the number of eligible drivers or require us to pay more to attract and retain drivers. A shortage of qualified drivers and intense competition for drivers from other companies would create difficulties in increasing the number of our drivers in the event we choose to expand our fleet of trucks. If we are unable to continue to attract and retain a sufficient number of qualified drivers, we could have difficulty meeting customer demands, any of which could materially and adversely affect our growth and profitability.

If we fail to maintain an effective system of internal controls, including internal control over financial reporting, we may be unable to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

We are subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended. We are also subject to the obligation under Section 404(a) of the Sarbanes Oxley Act of 2002 to annually review and report on our internal control over financial reporting, and to the obligation under Section 404(b) of the Sarbanes Oxley Act to engage our independent registered public accounting firm to attest to the effectiveness of our internal controls over financial reporting.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud, and operate successfully as a publicly traded partnership. Our efforts to maintain our internal controls may be unsuccessful, and we may be unable to maintain effective controls over financial reporting, including our disclosure control. Any failure to maintain effective internal control over financial reporting and disclosure controls could harm our operating results or cause us to fail to meet our reporting obligations. These risks may be heightened after a business combination, during the phase when we are implementing our internal control structure over the recently acquired business.

Given the difficulties inherent in the design and operation of internal control over financial reporting, we can provide no assurance as to either our or our independent registered public accounting firm’s conclusions about the effectiveness of internal controls in the future, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls could subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the market price of our common units.

In the fourth quarter of fiscal year 2016, we identified a material weakness in our internal control over financial reporting that existed through December 31, 2015. Our failure to establish and maintain effective internal control over financial reporting could result in material misstatements in our financial statements and cause investors to lose confidence in our reported financial information, which in turn could cause the trading price of our common units to decline.

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During the year ended March 31, 2016, we identified a material weakness in our internal control over financial reporting that existed through December 31, 2015, related to the appropriate policies and procedures in place to properly identify and account for liabilities related to contingent consideration payments in business combinations. We identified this material weakness in connection with the recording of business combinations in the fourth quarter of fiscal year 2016. As a result of such weakness, our Audit Committee, upon recommendation of management, determined to restate our unaudited quarterly financial information for the quarters ended June 30, 2015, September 30, 2015 and December 31, 2015. For further information regarding this matter, please refer to Item 9A. Controls and Procedures.

Management's ongoing assessment of internal control over financial reporting may in the future identify additional weaknesses and conditions that need to be addressed. Any failure to improve our internal control over financial reporting to address identified weaknesses in the future, if they were to occur, could prevent us from maintaining accurate accounting records and discovering material accounting errors, which in turn, could adversely affect our business and the value of our common units.

An impairment of goodwill and intangible assets could reduce our earnings.

At March 31, 2016, we had goodwill and intangible assets of $2.5 billion. Such assets are subject to impairment reviews on an annual basis, or at an interim date if information indicates that such asset values have been impaired. Any impairment we would be required to record in our financial statements would result in a charge to our income, which would reduce our earnings.

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

Our credit management procedures may not fully eliminate the risk of nonpayment by our customers. We manage our credit risk exposure through credit analysis, credit approvals, establishing credit limits, requiring prepayments (partially or wholly), requiring product deliveries over defined time periods, and credit monitoring. While we believe our procedures are effective, we can provide no assurance that bad debt write-offs in the future may not be significant and any such nonpayment problems could impact our consolidated results of operations and potentially limit our ability to make payments on our debt obligations or distributions to our unitholders.

Our terminaling operations depend on pipelines to transport crude oil, natural gas liquids and refined products.

We own natural gas liquids and crude oil terminals and lease refined products terminals. These facilities depend on pipeline and storage systems that are owned and operated by third parties. Any interruption of service on a pipeline or lateral connections or adverse change in the terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport product to and from our facilities and have a corresponding material adverse effect on our revenues. In addition, the rates charged by the interconnected pipelines for transportation to and from our facilities impact the utilization and value of our terminals. We have historically been able to pass through the costs of pipeline transportation to our customers. However, if competing pipelines do not have similar annual tariff increases or service fee adjustments, such increases could affect our ability to compete, thereby adversely affecting our revenues.

Our marketing operations depend on the availability of transportation and storage capacity.

Our product supply is transported and stored on facilities owned and operated by third parties. Any interruption of service on the pipeline or storage companies or adverse change in the terms and conditions of service could have a material adverse effect on our ability, and the ability of our customers, to transport products and have a corresponding material adverse effect on our revenues. In addition, the rates charged by the interconnected pipelines for transportation affects the profitability of our operations.

The financial results of our natural gas liquids businesses are seasonal and generally lower in the first and second quarters of our fiscal year, which may require us to borrow money to make distributions to our unitholders during these quarters.

The natural gas liquids inventory we have presold to customers is highest during summer months, and our cash receipts are lowest during summer months. As a result, our cash available for distribution for the summer is much lower than for the winter. With lower cash flow during the first and second fiscal quarters, we may be required to borrow money to pay distributions to our unitholders during these quarters. Any restrictions on our ability to borrow money could restrict our ability to pay the minimum quarterly distributions to our unitholders.

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A significant increase in fuel prices may adversely affect our transportation costs.

Fuel is a significant operating expense for us in connection with the delivery of products to our customers. A significant increase in fuel prices will result in increased transportation costs to us. The price and supply of fuel is unpredictable and fluctuates based on events we cannot control, such as geopolitical developments, supply and demand for oil and gas, actions by oil and gas producers, war and unrest in oil producing countries and regions, regional production patterns and weather concerns. As a result, any increases in these prices may adversely affect our profitability and competitiveness.

Some of our operations cross the United States/Canada border and are subject to cross-border regulation.

Our cross-border activities subject us to regulatory matters, including import and export licenses, tariffs, Canadian and United States customs and tax issues and toxic substance certifications. Such regulations include the "Short Supply Controls" of the Export Administration Act, the North American Free Trade Agreement and the Toxic Substances Control Act. Violations of these licensing, tariff and tax reporting requirements could result in the imposition of significant administrative, civil and criminal penalties.

The risk of terrorism and political unrest in various energy producing regions may adversely affect the economy and the price and availability of products.

An act of terror in any of the major energy producing regions of the world could potentially result in disruptions in the supply of crude oil and natural gas, the major sources of propane, which could have a material impact on the availability and price of propane. Terrorist attacks in the areas of our operations could negatively impact our ability to transport propane to our locations. These risks could potentially negatively impact our consolidated results of operations.

We depend on the leadership and involvement of key personnel for the success of our businesses.

We have certain key individuals in our senior management who we believe are critical to the success of our business. The loss of leadership and involvement of those key management personnel could potentially have a material adverse impact on our business and possibly on the market value of our units.

Risks Inherent in an Investment in Us

Our partnership agreement limits the fiduciary duties of our general partner to our unitholders and restricts the remedies available to our unitholders for actions taken by our general partner that might otherwise be breaches of fiduciary duty.

Fiduciary duties owed to our unitholders by our general partner are prescribed by law and our partnership agreement. The Delaware Revised Uniform Limited Partnership Act ("Delaware LP Act") provides that Delaware limited partnerships may, in their partnership agreements, restrict the fiduciary duties owed by the general partner to limited partners and the partnership. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- limits the liability and reduces the fiduciary duties of our general partner, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. As a result of purchasing common units, our unitholders consent to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable state law;
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permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its limited call right, its voting rights with respect to the units it owns and its determination whether or not to consent to any merger or consolidation of the partnership;

- provides that our general partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning our general partner subjectively believed that the decision was in, or not opposed to, the best interests of the partnership;
- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee and not involving a vote of our unitholders must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties or be “fair and reasonable” to us and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the

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totality of the relationships between the parties involved, including other transactions that may be particularly favorable or advantageous to us; and

- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

By purchasing a common unit, a common unitholder will become bound by the provisions of our partnership agreement, including the provisions described above.

Our general partner and its affiliates have conflicts of interest with us and limited fiduciary duties to our unitholders, and they may favor their own interests to the detriment of us and our unitholders.

The NGL Energy GP Investor Group owns and controls our general partner and its 0.1% general partner interest in us. Although our general partner has certain fiduciary duties to manage us in a manner beneficial to us and our unitholders, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owners. Furthermore, since certain executive officers and directors of our general partner are executive officers or directors of affiliates of our general partner, conflicts of interest may arise between the NGL Energy GP Investor Group and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders (see "–Our partnership agreement limits the fiduciary duties of our general partner to our unitholders and restricts the remedies available to our unitholders for actions taken by our general partner that might otherwise be breaches of fiduciary duty," above). The risk to our unitholders due to such conflicts may arise because of the following factors, among others:

- our general partner is allowed to take into account the interests of parties other than us, such as members of the NGL Energy GP Investor Group, in resolving conflicts of interest;
- neither our partnership agreement nor any other agreement requires owners of our general partner to pursue a business strategy that favors us;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner;
- our general partner determines which costs incurred by it are reimbursable by us;
- our general partner may cause us to borrow funds to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- our partnership agreement permits us to classify up to $20.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner interest or the incentive distribution rights ("IDRs");
- our partnership agreement does not restrict our general partner from causing 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;
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our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;

- our general partner controls the enforcement of the obligations that it and its affiliates owe to us;

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- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's IDRs without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

In addition, certain members of the NGL Energy GP Investor Group and their affiliates currently hold interests in other companies in the energy and natural resource sectors. Our partnership agreement provides that our general partner will be restricted from engaging in any business activities other than acting as our general partner and those activities incidental to its ownership interest in us. However, members of the NGL Energy GP Investor Group are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. As a result, they could potentially compete with us for acquisition opportunities and for new business or extensions of the existing services provided by us.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers, directors and owners. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

Even if our unitholders are dissatisfied, they have limited voting rights and are not entitled to elect our general partner or its directors.

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 will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner is chosen entirely by its members and not by our unitholders. Unlike publicly traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. Furthermore, if our unitholders are dissatisfied with the performance of our general partner, they will have limited ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also 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 the manner or direction of management.

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 of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their direct transferees and their indirect transferees approved by our general partner (which approval may be granted in its sole discretion) and persons who acquired such units with the prior approval of our general partner, cannot vote on any matter.

Our general partner interest or the control of our general partner may be transferred to a third party without the consent of our unitholders.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the members of the NGL Energy GP Investor Group to transfer all or a portion of their ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

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The IDRs of our general partner may be transferred to a third party.

Prior to the first day of the first quarter beginning after the 10th anniversary of the closing date of our IPO, a transfer of IDRs by our general partner requires (except in certain limited circumstances) the consent of a majority of our outstanding common units (excluding common units held by our general partner and its affiliates). However, after the expiration of this period, our general partner may transfer its IDRs to a third party at any time without the consent of our unitholders. If our general partner transfers its IDRs to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its IDRs.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, our unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or may receive a negative return on their investment. Our unitholders may also incur a tax liability upon a sale of their units.

Cost reimbursements to our general partner may be substantial and could reduce our cash available to make quarterly distributions to our unitholders.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf, which will be determined by our general partner in its sole discretion in accordance with the terms of our partnership agreement. In determining the costs and expenses allocable to us, our general partner is subject to its fiduciary duty, as modified by our partnership agreement, to the limited partners, which requires it to act in good faith. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us. We are managed and operated by executive officers and directors of our general partner. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates, will reduce the amount of cash available for distribution to our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily on external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, as well as reserves we have established to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or the agreements governing our indebtedness on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

We may issue additional units without the approval of our unitholders, which would dilute the interests of existing unitholders.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. Our issuance of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of available cash for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;

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- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Our general partner, without the approval of our unitholders, may elect to cause us to issue common units while also maintaining its general partner interest in connection with a resetting of the target distribution levels related to its IDRs. This could result in lower distributions to our unitholders.

Our general partner has the right to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units. The number of common units to be issued to our general partner will be equal to that number of common units that would have entitled their holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the IDRs in the prior two quarters. We anticipate that our general partner would exercise this reset right to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that our general partner could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its IDRs and may, therefore, desire to be issued common units rather than retain the right to receive distributions on its IDRs based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units and general partner interests to our general partner in connection with resetting the target distribution levels.

Our unitholders’ liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. 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 other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state’s partnership statute; or
- a unitholder’s 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 constitute “control” of our business.

Our unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware LP Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. 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. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interests nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware LP Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability.

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Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. We could lose our status as a partnership for a number of reasons, including not having enough "qualifying income." If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes, our 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. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, a publicly traded partnership such as us will be treated as a corporation for federal income tax purposes unless, for each taxable year, 90% or more of its gross income is "qualifying income" under Section 7704 of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"). "Qualifying income" includes income and gains derived from the exploration, development, production, processing, transportation, storage and marketing of natural gas, natural gas products, and crude oil or other passive types of income such as certain interest and dividends and gains from the sale or other disposition of capital assets held for the production of income that otherwise constitutes qualifying income. Although we do not believe based upon our current operations that we are treated as a corporation, we could be treated as a corporation for federal income tax purposes or otherwise subject to taxation as an entity if our gross income is not properly classified as qualifying income, there is a change in our business or there is a change in current law.

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 would pay state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, 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 market value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to our unitholders. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may 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 income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of the United States Congress propose and consider substantive changes to the existing United States federal income tax laws that affect the tax treatment of publicly traded partnerships. Members of Congress have recently proposed substantive changes to the existing United States tax laws that would affect certain publicly traded partnerships, if such proposals are enacted into law. The Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. If successful, the Obama administration's proposal, or other similar proposals, could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for United States federal income tax purposes.

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We are unable to predict whether any such change or other proposals will ultimately be enacted or will affect our tax treatment. Any modification to the income tax laws and interpretations thereof may or may not be applied retroactively and could, among other things, cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. Moreover, such modifications and change in interpretations may affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. Although we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted, any such changes could negatively impact the value of an investment in our common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. 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. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

Because we expect to be treated as a partnership for United States federal income tax purposes, our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

If 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 the unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units the unitholder sells will, in effect, become taxable income to the unitholder if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized on any sale of common units, 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 includes a unitholder's share of our nonrecourse liabilities, if a unitholder sell units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investment in common units by tax exempt entities, such as employee benefit plans, individual retirement accounts ("IRAs"), Keogh plans and other retirement plans and non-United States persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are 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-United States persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-United States persons will be required to file United States federal income tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-United States person, you should consult your tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. Any position we take that is inconsistent with applicable Treasury Regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our unitholders. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our

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unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the market value of our common units or result in audit adjustments to tax returns of unitholders.

We have subsidiaries that are treated as corporations for federal income tax purposes and subject to corporate level income taxes.

We conduct a portion of our operations through subsidiaries that are corporations for federal income tax purposes. We may elect to conduct additional operations in corporate form in the future. Our corporate subsidiaries will be subject to corporate level tax, which will reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS or other state or local jurisdictions were to successfully assert that our corporate subsidiaries have more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, our cash available for distribution to our unitholders would be further reduced.

We prorate our items of income, gain, loss and deduction for United States federal income tax purposes between transferors and transferees of our units each month based on the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based on the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The United States Treasury Department, however, has issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. Therefore, the use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a “short seller” to affect a short sale of units may be considered as having disposed of those common units. If so, such unitholder would no longer be treated for federal income 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 unitholder whose units are loaned to a “short seller” to effect a short sale of 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 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 units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those 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 consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies and monthly conventions for United States federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner and our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Internal Revenue Code Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of taxable income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable 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.

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The sale or exchange of 50% or more of our capital and profits interests during 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 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 unit will be counted only once. While we would continue our existence as a Delaware limited partnership, our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a significant 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 his taxable income for the year of termination. A technical termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be 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 for failure to file a timely return if we are unable to determine that a technical termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

There are limits on the deductibility of our losses that may adversely affect our unitholders.

There are a number of limitations that may prevent unitholders from using their allocable share of our losses as a deduction against unrelated income. In cases where our unitholders are subject to the passive loss rules (generally, individuals and closely held corporations), any losses generated by us will only be available to offset our future income and cannot be used to offset income from other activities, including other passive activities or investments. Unused losses may be deducted when the unitholder disposes of its entire investment in us in a fully taxable transaction with an unrelated party. A unitholder's share of our net passive income may be offset by unused losses from us carried over from prior years but not by losses from other passive activities, including losses from other publicly traded partnerships. Other limitations that may further restrict the deductibility of our losses by a unitholder include the at-risk rules and the prohibition against loss allocations in excess of the unitholder's tax basis in its units.

Purchasers of our common units may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, holders of our common units are subject to other taxes, including foreign, state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own or control property now or in the future. Holders of our common units are required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions and may be subject to penalties for failure to comply with those requirements. We own assets and conduct business in a number of states, most of which impose a personal income tax on individuals. Most of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own or control assets or conduct business in additional states that impose a personal income tax.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Overview. We believe that we have satisfactory title or valid rights to use all of our material properties. Although some of these properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under non-compete agreements entered into in connection with acquisitions and other encumbrances, easements and restrictions, we do not believe that any of these burdens will materially interfere with our continued use of these properties in our business, taken as a whole. Our obligations under our credit facilities are secured by liens and mortgages on substantially all of our real and personal property.

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Other than as described below, we believe that we have all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local governmental and regulatory authorities that relate to ownership of our properties or the operations of our business.

One of our facilities acquired in the High Sierra merger is operating with all but one of the required permits, as the State of Wyoming has not yet developed a process for issuing permits of this type. We believe that the permit will ultimately be granted, but we are unable to determine the timing of any action by the State of Wyoming.

Our corporate headquarters are in Tulsa, Oklahoma and are leased. We also lease corporate offices in Denver, Colorado and Houston, Texas.

For additional information regarding our properties and the reportable segments in which they are used, see Part I, Item 1–"Business."

Item 3. Legal Proceedings

We are involved from time to time in various legal proceedings and claims arising in the ordinary course of business. For information related to legal proceedings, please see the discussion under the captions "Legal Contingencies," "Contractual Disputes," and "Environmental Matters" in Note 10 to our consolidated financial statements included in this Annual Report, which information is incorporated by reference into this Item 3.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

Market Information

Our common units are listed on the New York Stock Exchange (“NYSE”) under the symbol “NGL.” Our common units began trading on the NYSE on May 12, 2011. Prior to May 12, 2011, our common units were not listed on any exchange or traded in any public market. At May 23, 2016, there were approximately 245 common unitholders of record which does not include unitholders for whom common units may be held in “street name.”

The following table summarizes the high and low sales prices per common unit for the periods indicated as reported on the New York Stock Exchange Composite Transactions tape, and the amount of cash distributions paid per common unit.

	Price Range		Cash
	High	Low	Distribution
2016 Fiscal Year			
Fourth Quarter	$15.16	$5.57	$ 0.6400
Third Quarter	23.33	8.04	0.6400
Second Quarter	31.31	19.55	0.6325
First Quarter	33.64	26.11	0.6250
2015 Fiscal Year			
Fourth Quarter	$31.70	$24.88	$ 0.6175
Third Quarter	40.58	22.57	0.6088
Second Quarter	44.86	39.13	0.5888
First Quarter	46.25	37.08	0.5513

Cash Distribution Policy

Available Cash

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders as of the record date. Available cash for any quarter generally consists of all cash on hand at the end of that quarter, less the amount of cash reserves established by our general partner, to (i) provide for the proper conduct of our business, (ii) comply with applicable law, any of our debt instruments or other agreements, and (iii) provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters.

General Partner Interest

Our general partner is entitled to 0.1% of all quarterly distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its 0.1% general partner interest. Our general partner’s interest in our distributions may be reduced if we issue additional limited partner units in the future (other than the issuance of common units upon a reset of the IDRs) and our general partner does not contribute a proportionate amount of capital to us to maintain its 0.1% general partner interest.

Incentive Distribution Rights

The general partner will also receive, in addition to distributions on its 0.1% general partner interest, additional distributions based on the level of distributions to the limited partners. These distributions are referred to as "incentive distributions" or "IDRs." Our general partner currently holds the IDRs, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

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The following table illustrates the percentage allocations of available cash from operating surplus between our unitholders and our general partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest In Distributions" are the percentage interests of our general partner and our unitholders in any available cash from operating surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution Per Unit," until available cash from operating surplus we distribute reaches the next target distribution level, if any. The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 0.1% general partner interest, and assume that our general partner has contributed any additional capital necessary to maintain its 0.1% general partner interest and has not transferred its IDRs.

	Total Quarterly Distribution Per Unit				Marginal Percentage Interest In Distributions: Unitholders	Marginal Percentage Interest In Distributions: General Partner
Minimum quarterly distribution				$0.337500	99.9%	0.1 %
First target distribution	above	$0.337500	up to	$0.388125	99.9%	0.1 %
Second target distribution	above	$0.388125	up to	$0.421875	86.9%	13.1 %
Third target distribution	above	$0.421875	up to	$0.506250	76.9%	23.1 %
Thereafter	above	$0.506250			51.9%	48.1 %

The maximum distribution of 48.1% does not include any distributions that our general partner may receive on common units that it owns.

Restrictions on the Payment of Distributions

As described in Note 8 to our consolidated financial statements included in this Annual Report, our Credit Agreement contains covenants limiting our ability to pay distributions if we are in default under the Credit Agreement and to pay distributions that are in excess of available cash, as defined in the Credit Agreement.

Sales of Unregistered Securities

During the year ended March 31, 2016, we completed two acquisitions in which we issued unregistered common units as partial consideration. All of these units were issued in reliance upon the exemption from registration provided by Section 4(a)(2) of the Securities Act of 1933, as amended ("Securities Act"), as the units were issued to the owners of businesses acquired in privately negotiated transactions not involving any public offering or solicitation. During October 2015, we issued 52,199 common units to the sellers of a retail propane business. During the year ended March 31, 2016, we issued 781,255 common units to the sellers of two water treatment and disposal facilities.

Common Unit Repurchase Program

On September 10, 2015, the Board of Directors of our general partner authorized a common unit repurchase program pursuant to which we could repurchase up to $45 million of our outstanding common units through March 31, 2016 from time to time in the open market or in other privately negotiated transactions. The following table summarizes the repurchase of common units during the three months ended March 31, 2016.

Period	Total Number of Common	Average Price Paid Per	Total Number of Common	Approximate Dollar Value of Common

	Units Purchased	Common Unit	Units Purchased as Part of a Publicly Announced Program	Units that May Yet Be Purchased Under the Program
January 1-31, 2016	8,403	$ 11.02	—	$ 37,272,180
February 1-29, 2016	782,703	7.92	782,703	31,073,172
March 1-31, 2016	442,960	8.67	442,960	27,232,709
Total	1,234,066	$ 8.19	1,225,663	$ —

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The common units not repurchased under the publicly announced program were surrendered by employees to pay tax withholding in connection with the vesting of restricted common units. As a result, we are including the common units surrendered in the “Total Number of Common Units Purchased” column.

Securities Authorized for Issuance Under Equity Compensation Plans

In connection with the completion of our IPO, our general partner adopted the NGL Energy Partners LP Long-Term Incentive Plan. Please see Part III, Item 12–“Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters–Securities Authorized for Issuance Under Equity Compensation Plan” which is incorporated by reference into this Item 5.

Item 6. Selected Financial Data

The following table summarizes selected historical financial and operating data for the periods and as of the dates indicated. The following table should be read in conjunction with Part I, Item 7–“Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the financial statements and related notes included in this Annual Report.

The selected consolidated historical financial data (excluding volume information) at March 31, 2016 and 2015, and for each of the three years in the period ended March 31, 2016 is derived from our audited historical consolidated financial statements included in this Annual Report. The selected consolidated historical financial data (excluding volume information) at March 31, 2014, 2013 and 2012 and for each of the two years in the period ended March 31, 2013 is derived from our audited historical consolidated financial statements not included in this Annual Report.

Correction of Error

We have changed our previously issued consolidated balance sheet as of March 31, 2015 and consolidated statement of operations, consolidated statement of comprehensive income, consolidated statement of changes in equity, and consolidated statement of cash flows for the year ended March 31, 2015 for the correction of an immaterial error (see Note 17 to our consolidated financial statements included in this Annual Report).

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	Year Ended March 31,				
	2016	2015	2014	2013	2012
	(in thousands, except per unit data)				
Income Statement Data (1)(2)					
Total revenues	$11,742,110	$16,802,057	$9,699,274	$4,417,767	$1,310,473
Total cost of sales	10,839,037	15,958,207	9,132,699	4,039,110	1,217,023
Operating (loss) income	(104,603)	107,420	106,565	87,307	15,030
Interest expense	133,089	110,123	58,854	32,994	7,620
(Gain) loss on early extinguishment of debt	(28,532)	—	—	5,769	—
Net (loss) income attributable to parent equity	(198,929)	37,306	47,655	47,940	7,876
Basic and diluted (loss) income per common unit	(2.35)	(0.05)	0.51	0.96	0.32
Cash Flows Data (1)(2)					
Net cash provided by operating activities	$351,495	$262,391	$85,236	$132,634	$90,329
Net cash used in investing activities	(445,327)	(1,366,221)	(1,455,373)	(546,621)	(296,897)
Net cash provided by financing activities	80,705	1,134,693	1,369,016	417,716	198,063
Cash distributions paid per common unit (subsequent to IPO)	2.54	2.37	2.01	1.69	0.85
Cash distributions paid per common unit (prior to IPO)					0.35
Balance Sheet Data - Period End (1)(2)(3)					
Total assets (4)	$5,560,155	$6,655,792	$4,134,910	$2,290,901	$749,519
Total long-term obligations, exclusive of debt issuance costs and current maturities (4)	3,160,073	2,842,493	1,628,173	741,924	199,389
Total equity	1,694,065	2,693,432	1,531,853	889,418	405,329
Volume Information (1)					
Retail propane sold (gallons)	152,238	169,279	162,361	144,379	78,236
Distillates sold (gallons)	30,674	34,862	34,965	28,853	1,650
Wholesale propane sold (gallons) (5)	1,244,529	1,285,707	1,190,106	912,625	659,921
Wholesale other products sold (gallons)	843,922	825,514	786,671	505,529	134,999
Crude oil sold (barrels)	67,211	83,864	46,107	24,373	—
Water received (barrels)	208,440	161,664	75,451	25,009	—
Refined products sold (barrels)	98,988	68,043	9,833	—	—
Renewable products sold (barrels)	5,794	5,318	3,593	—	—

(1) The acquisitions of businesses affect the comparability of this information.

(2) On February 1, 2016, we sold our general partner interest in TLP. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting.

(3) Certain balance sheet data at March 31, 2015 was adjusted to reflect the final acquisition accounting for certain business combinations (see Note 2 to our consolidated financial statements included in this Annual Report).

(4) Revised to reclassify debt issuance costs for our senior notes from intangible assets to long-term debt obligations for all balance sheet dates presented (see Note 2 to our consolidated financial statements included in this Annual Report).

(5) Includes intercompany volumes sold to our retail propane segment.

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

Overview

We are a Delaware limited partnership (the "Partnership") formed in September 2010. NGL Energy Holdings LLC serves as our general partner. On May 17, 2011, we completed our initial public offering ("IPO"). Subsequent to our IPO, we significantly expanded our operations through numerous acquisitions, as described under Part I, Item 1–"Business–Acquisitions." At March 31, 2016, our operations include:

- Crude Oil Logistics
- Water Solutions
- Liquids
- Retail Propane
- Refined Products and Renewables

Correction of Error

We have changed our previously issued consolidated balance sheet as of March 31, 2015 and consolidated statement of operations, consolidated statement of comprehensive income, consolidated statement of changes in equity, and consolidated statement of cash flows for the year ended March 31, 2015 for the correction of an immaterial error (see Note 17 to our consolidated financial statements included in this Annual Report).

Crude Oil Logistics

Our crude oil logistics segment purchases crude oil from producers and transports it to refineries or for resale at owned and leased pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs. The assets of our crude oil logistics segment include owned and leased crude oil storage terminals and pipeline injection stations, a fleet of owned trucks and trailers, a fleet of owned and leased railcars, a fleet of owned barges and towboats, and interests in two crude oil pipelines.

Most of our contracts to purchase or sell crude oil are at floating prices that are indexed to published rates in active markets such as Cushing, Oklahoma. We attempt to reduce our exposure to price fluctuations by using back-to-back physical contracts whenever possible. When back-to-back physical contracts are not optimal, we enter into financially settled derivative contracts as economic hedges of our physical inventory, physical sales and physical purchase contracts. We use our transportation assets to move crude oil from the wellhead to the highest value market. Spreads between crude oil prices in different markets can fluctuate, which may expand or limit our opportunity to generate margins by transporting crude oil to different markets.

The following table summarizes the range of low and high spot crude oil prices per barrel of NYMEX West Texas Intermediate Crude Oil at Cushing, Oklahoma for the periods indicated and the prices at period end:

	Spot Price Per Barrel		
Year Ended March 31,	Low	High	At Period End
2016	$26.21	$61.43	$ 38.34
2015	43.46	107.26	47.60
2014	86.68	110.53	101.58

We believe volatility in commodity prices will continue, and our ability to adjust to and manage this volatility may impact our financial results.

Our crude oil logistics segment generated an operating loss of $40.7 million during the year ended March 31, 2016, compared to an operating loss of $35.8 million during the year ended March 31, 2015. The operating loss during the year ended March 31, 2016 included a write-down of $47.7 million related to pipe we no longer expect to use in the originally-planned Grand Mesa Pipeline.

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Water Solutions

Our water solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms and drilling fluids and performs truck washouts. In addition, our water solutions segment sells the recycled water and recovered hydrocarbons that result from performing these services. The assets of our water solutions segment include water pipelines, water treatment and disposal facilities, washout facilities, and solid waste disposal facilities.

Our water processing facilities are strategically located near areas of high crude oil and natural gas production. A significant factor affecting the profitability of our water solutions segment is the extent of exploration and production in the areas near our facilities, which is generally based upon producers' expectations about the profitability of drilling new wells. The primary customer of our Wyoming facility has committed to deliver a specified minimum volume of water to our facility under a long-term contract. The primary customers of our Colorado facilities have committed to deliver all wastewater produced at wells in a designated area to our facilities. One customer in Texas has committed to deliver at least 50,000 barrels of wastewater per day to our facilities. Most customers of our other facilities are not under volume commitments, although certain of our facilities are connected to producer locations by pipeline.

Our water solutions segment generated an operating loss of $313.7 million during the year ended March 31, 2016, compared to operating income of $65.3 million during the year ended March 31, 2015. The operating loss during the year ended March 31, 2016 included a goodwill impairment of $380.2 million as the decline in crude oil prices and crude oil production have had an unfavorable impact on our water solutions business.

Liquids

Our liquids segment purchases propane, butane, and other products from refiners, processing plants, producers, and other parties, and sells the products to retailers, wholesalers, refiners, and petrochemical plants throughout the United States and in Canada. Our liquids segment owns 19 terminals throughout the United States and a salt dome storage facility in Utah, operates a fleet of leased railcars, and leases underground storage capacity. We attempt to reduce our exposure to price fluctuations by using back-to-back physical contracts and pre-sale agreements that allow us to lock in a margin on a percentage of our winter volumes. We also enter into financially settled derivative contracts as economic hedges of our physical inventory, physical sales and physical purchase contracts.

Our wholesale liquids business is a "cost-plus" business that can be affected by both price fluctuations and volume variations. We establish our selling price based on a pass-through of our product supply, transportation, handling, storage, and capital costs plus an acceptable margin. The margin we realize in our wholesale liquids business is substantially less on a per gallon basis than the margin we realize in our retail propane business.

Weather conditions and gasoline blending can have a significant impact on the demand for propane and butane, and sales volumes and prices are typically higher during the colder months of the year. Consequently, our revenues, operating profits, and operating cash flows are typically lower in the first and second quarters of each fiscal year.

The following table summarizes the range of low and high spot propane prices per gallon at Conway, Kansas, and Mt. Belvieu, Texas, two of our main pricing hubs, for the periods indicated and the prices at period end:

	Conway, Kansas Spot Price Per Gallon			Mt. Belvieu, Texas Spot Price Per Gallon		
Year Ended March 31,	Low	High	At Period End	Low	High	At Period End
2016	$ 0.27	$ 0.51	$ 0.39	$ 0.30	$ 0.57	$ 0.44
2015	0.38	1.13	0.45	0.45	1.13	0.51
2014	0.77	4.33	1.03	0.81	1.73	1.06

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The range of low and high spot butane prices per gallon at Mt. Belvieu, Texas for the periods indicated and the prices at period end:

	Spot Price Per Gallon		
Year Ended March 31,	Low	High	At Period End
2016	$ 0.42	$ 0.68	$ 0.53
2015	0.60	1.30	0.63
2014	1.08	1.64	1.26

We believe volatility in commodity prices will continue, and our ability to adjust to and manage this volatility may impact our financial results.

Our liquids segment generated operating income of $76.2 million and $45.1 million during the years ended March 31, 2016 and 2015, respectively. During the year ended March 31, 2016, we wrote off assets of $14.6 million acquired as part of the Gavilon Energy acquisition that we deemed no longer recoverable. Operating income during the year ended March 31, 2015 was reduced by a loss of $29.8 million on the sale of a natural gas liquids terminal. Additionally, Sawtooth NGL Caverns, LLC (“Sawtooth”), which we acquired in February 2015, generated $9.8 million of operating income during the year ended March 31, 2016.

Retail Propane

Our retail propane segment is a “cost-plus” business that sells propane, distillates, and equipment and supplies to end users consisting of residential, agricultural, commercial, and industrial customers and to certain resellers in 25 states and the District of Columbia. Our retail propane segment purchases the majority of its propane from our liquids segment. Our retail propane segment generates margins based on the difference between the wholesale cost of product and the selling price of the product in the retail markets. These margins fluctuate over time due to supply and demand conditions. Weather conditions can have a significant impact on our sales volumes and prices, as a large portion of our sales are to residential customers who purchase propane and distillates for home heating purposes.

A significant factor affecting the profitability of our retail propane segment is our ability to maintain our product margin. Product margin is the difference between our sales prices and our total product costs, including transportation and storage. We monitor wholesale propane prices daily and adjust our retail prices accordingly. We believe volatility in commodity prices will continue, and our ability to adjust to and manage this volatility may impact our financial results.

The retail propane business is both weather-sensitive and subject to seasonal volume variations due to propane’s primary use as a heating source in residential and commercial buildings and for agricultural purposes. Consequently, our revenues, operating profits, and operating cash flows are typically lower in the first and second quarters of each fiscal year.

Our retail propane segment generated operating income of $44.1 million and $64.1 million during the years ended March 31, 2016 and 2015, respectively.

Refined Products and Renewables

Our refined products and renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations. We purchase refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedule them for delivery at various locations. As discussed in “Recent Developments” below, on February 1, 2016, we sold our general partner interest in TLP.

We purchase refined petroleum products primarily in the Gulf Coast, Southeast, and Midwest regions of the United States and schedule them for delivery primarily on the Colonial, Plantation, and Magellan pipelines. We sell our products to commercial and industrial end users, independent retailers, distributors, marketers, government entities, and other wholesalers of refined petroleum products. We sell our products at TLP's terminals and at terminals owned by third parties.

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The following table summarizes the range of low and high spot gasoline prices per barrel using NYMEX gasoline prompt-month futures for the periods indicated and the prices at period end:

	Spot Price Per Barrel		
Year Ended March 31,	Low	High	At Period End
2016	$37.75	$90.15	$ 59.91
2015	53.34	131.46	74.76
2014 (1)	109.20	126.84	122.22

(1) Prices are for the four months ended March 31, 2014 as we acquired Gavilon, LLC (“Gavilon Energy”) on December 2, 2013.

The following table summarizes the range of low and high spot diesel prices per barrel using NYMEX ULSD prompt-month futures for the periods indicated and the prices at period end:

	Spot Price Per Barrel		
Year Ended March 31,	Low	High	At Period End
2016	$36.36	$84.68	$ 49.76
2015	68.04	128.10	72.24
2014 (1)	121.80	137.76	123.06

(1) Prices are for the four months ended March 31, 2014 as we acquired Gavilon Energy on December 2, 2013.

Our refined products and renewables segment generated operating income of $227.0 million and $54.6 million during the years ended March 31, 2016 and 2015, respectively. Our refined products and renewables segment was significantly expanded with our July 2014 acquisition of TransMontaigne. Operating income during the year ended March 31, 2016 was also increased by a gain of $130.4 million recorded on the sale of our general partner interest in TLP during the three months ended March 31, 2016, as discussed in “Recent Developments” below and Note 14 to our consolidated financial statements included in this Annual Report.

Trends

Crude oil prices can fluctuate widely based on changes in supply and demand conditions. The opportunity to generate revenues in our crude oil logistics business is heavily influenced by the volume of crude oil being produced. Crude oil prices declined sharply during the period from July 2014 through March 2016 (the spot price for NYMEX West Texas Intermediate crude oil at Cushing, Oklahoma declined from $105.34 per barrel at July 1, 2014 to $38.34 per barrel at March 31, 2016). While crude oil production in the United States has been strong in recent years, the sharp decline in crude oil prices has reduced the incentive for producers to expand production. If crude oil prices remain low, resultant declines in crude oil production may adversely impact volumes in our crude oil logistics business.

Since January 2015, crude oil markets have been in contango (a condition in which forward crude oil prices are greater than spot prices). Our crude oil logistics business benefits when the market is in contango, as higher forward prices result in inventory holding gains between the time we financially hedge a barrel in inventory and physically sell the same barrel. In addition, we are able to better use our storage assets when crude oil markets are in contango.

Our opportunity to generate revenues in our water solutions business is based on the level of production of natural gas and crude oil in the areas where our facilities are located. As described above, crude oil prices declined sharply since July 2014. At current market prices, drilling rigs and production have decreased and adversely impacted the volumes of our water solutions business. A portion of the revenues of our water solutions business is generated from the sale of hydrocarbons that we recover when processing the wastewater. Because of this, lower crude oil prices result in lower per-barrel revenues for our water solutions business.

An important element of our refined products and renewables segment relates to the marketing of refined products in the Southeast and East Coast regions. We purchase product in the Gulf Coast, transport the product on third party pipelines, and sell the product primarily at TLP’s refined products terminals. Most of the contracts with these customers are one year in

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duration, with pricing indexed to prices in the Gulf Coast at the date of sale plus a specified differential. To operate this business we maintain inventory in transit on the third party pipelines and at the destination terminals where we sell the product. The value of this inventory will increase or decrease as market prices change. In order to mitigate this risk, we enter into futures contracts, which are only available based on New York Harbor pricing. Because our contracts are indexed to Gulf Coast prices and our futures contracts are based on New York Harbor prices, the futures contracts are not a perfect hedge against our inventory holding risk. During any given quarter, spreads between prices in the Gulf Coast and New York Harbor could narrow or widen, which could reduce the effectiveness of the futures contracts as a hedge of the inventory holding risk. The tenor of these futures contracts, which are typically six months to one year in duration at inception, can also contribute to volatility in earnings among individual quarters within a fiscal year.

During the year ended March 31, 2016, prices for refined products declined. Gulf Coast prices, on which our sales contracts are based, declined more than the New York Harbor prices, on which our futures contracts are based, which had an adverse impact on our cost of sales. Based on historical experience, we generally expect the spreads between Gulf Coast and New York Harbor prices to be more consistent over the course of a contract year than during any individual quarter within the year, and that we should expect more volatility in cost of sales among quarters within a fiscal year than we would expect during a full fiscal year.

The decline in crude oil prices has had an adverse impact on many participants in the energy markets, and the inherent risk of customer or counterparty nonperformance is higher when crude oil prices are low or in decline.

Seasonality

Seasonality impacts our liquids and retail propane segments. A large portion of our retail propane business is in the residential market where propane is used primarily for home heating purposes. Consequently, for these two segments, revenues, operating profits and operating cash flows are generated mostly in the third and fourth quarters of each fiscal year. See "–Liquidity, Sources of Capital and Capital Resource Activities–Cash Flows."

Recent Developments

Grand Mesa Pipeline

In September 2014, we entered into a joint venture with RimRock Midstream, LLC ("RimRock") whereby each party owned a 50% interest in Grand Mesa Pipeline, LLC ("Grand Mesa"). In October 2014, we obtained ship-or-pay volume commitments from multiple shippers to begin construction of the Grand Mesa Pipeline, which will originate in Colorado and terminate in Cushing, Oklahoma. In November 2014, we acquired RimRock's 50% ownership interest in Grand Mesa for $310.0 million in cash. In November 2015, Grand Mesa Pipeline entered into an agreement with Saddlehorn Pipeline Company, LLC ("Saddlehorn"), under which we acquired a 37.5% undivided interest in a crude oil pipeline currently under construction (the "Joint Pipeline"). The Joint Pipeline will take receipt from Grand Mesa Pipeline's origin in Colorado and will deliver to Cushing, Oklahoma. We will have the right to utilize 150,000 barrels per day of capacity on the Joint Pipeline. Operating costs will be allocated to us based on our proportionate ownership interest and throughput. We expect the Joint Pipeline to be operational beginning in the third quarter of fiscal year 2017.

Through our undivided interest in the Joint Pipeline, we will have expanded capacity, sufficient to service our customer contracts at the same origin and termination points with the ability to accept additional volume commitments. We will retain ownership of our previously-acquired easements for the potential future development of transportation projects involving petroleum commodities other than crude oil and condensate. With the consent and participation of Saddlehorn, we and Saddlehorn may consider future opportunities using these easements for projects involving the transportation of crude oil and condensate.

We estimate that our share of the cost to construct the Joint Pipeline will be $250 million. We paid $211 million towards the construction of the pipeline during the year ended March 31, 2016, and we expect to pay the remaining $39 million during the fiscal year ending March 31, 2017. Also, as part of the Joint Pipeline project, we are constructing certain assets that will be connected to the Joint Pipeline. The estimated costs for these assets are $117.0 million. We spent $36.4 million on the construction of these assets during the year ended March 31, 2016, and expect to pay the remaining $80.6 million during the fiscal year ending March 31, 2017.

During the fourth quarter of fiscal year 2016, we recorded a write-down of $47.7 million related to pipe we no longer expect to use in the originally-planned Grand Mesa Pipeline, which is reported within loss on disposal or impairment of assets, net. In addition, during the six months ended March 31, 2016, we reclassified $47.0 million of costs to acquire land, rights-of-

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way and easements on the originally-planned Grand Mesa Pipeline route to intangible assets. As discussed above, we acquired an undivided interest in a different crude oil pipeline with the same origin and destination points as those of our originally-planned Grand Mesa Pipeline route. We will retain the land, rights-of-way and easements along the originally-planned Grand Mesa Pipeline route for potential future development.

Sale of General Partner Interest in TLP

On February 1, 2016, we completed the sale of our general partner interest in TLP to an affiliate of ArcLight Capital Partners ("ArcLight") for $350 million in cash and recorded a gain on disposal of $329.9 million during the three months ended March 31, 2016. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting. As part of this transaction, we entered into lease agreements whereby we will remain the long-term exclusive tenant in the TLP Southeast terminal system. As a result of entering into these leases, we deferred $204.6 million of the gain on the sale and will recognize this amount over our future lease payment obligations, which is approximately seven years. During the three months ended March 31, 2016, we recognized $5.0 million of the deferred gain in our consolidated statement of operations. In addition, we retained TransMontaigne's marketing business, which is a significant part of our refined products and renewables segment, and TransMontaigne Product Services, LLC, its customer contracts and its line space on the Colonial and Plantation pipelines.

Subsequent Events

Sale of TLP Common Units

On April 1, 2016, we sold all of the TLP common units we owned to ArcLight for approximately $112.4 million in cash.

Class A Convertible Preferred Units

On April 21, 2016, we entered into an agreement to issue $200 million of 10.75% Class A Convertible Preferred Units ("Preferred Units") to Oaktree Capital Management L.P. ("Oaktree"). Oaktree may acquire 16.6 million Preferred Units at a price of $12.03 per unit as well as 3.6 million warrants, which are subject to certain vesting and exercise terms. We expect to use the net proceeds from the issuance of the Preferred Units to repay borrowings outstanding on our Revolving Credit Facility (as hereinafter defined), which may be re-borrowed in the future to fund capital expenditures and for other general partnership purposes. The first closing of this transaction occurred on May 11, 2016 and we received gross proceeds of $100 million. We expect the second closing to occur prior to June 30, 2016.

Acquisitions

The acquisitions disclosed in Part I, Item 1–"Business–Acquisitions" impact the comparability of our results of operations between our current and prior fiscal years.

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Consolidated Results of Operations

The following table summarizes our consolidated statements of operations for the periods indicated:

	Year Ended March 31,		
	2016	2015	2014
	(in thousands)		
Total revenues	$11,742,110	$16,802,057	$9,699,274
Total cost of sales	10,839,037	15,958,207	9,132,699
Operating expenses	401,118	364,131	259,799
General and administrative expense	139,541	149,430	75,860
Depreciation and amortization	228,924	193,949	120,754
Loss on disposal or impairment of assets, net	320,766	41,184	3,597
Revaluation of liabilities	(82,673)	(12,264)	—
Operating (loss) income	(104,603)	107,420	106,565
Equity in earnings of unconsolidated entities	16,121	12,103	1,898
Interest expense	(133,089)	(110,123)	(58,854)
Gain on early extinguishment of debt	28,532	—	—
Other income, net	5,575	37,171	86
(Loss) income before income taxes	(187,464)	46,571	49,695
Income tax benefit (expense)	367	3,622	(937)
Net (loss) income	(187,097)	50,193	48,758
Less: Net income allocated to general partner	(47,620)	(45,700)	(14,148)
Less: Net income attributable to noncontrolling interests	(11,832)	(12,887)	(1,103)
Net (loss) income allocated to limited partners	$(246,549)	$(8,394)	$33,507

See the detailed discussion of revenues, cost of sales, operating expenses, general and administrative expenses, and depreciation and amortization expense by segment below.

Non-GAAP Financial Measures

In addition to financial results reported in accordance with accounting principles generally accepted in the United States ("GAAP"), we have provided the non-GAAP financial measures of EBITDA and Adjusted EBITDA. These non-GAAP financial measures are not intended to be a substitute for those reported in accordance with GAAP. These measures may be different from non-GAAP financial measures used by other entities, even when similar terms are used to identify such measures.

We define EBITDA as net income (loss) attributable to parent equity, plus interest expense, gain on early extinguishment of debt, income tax expense (benefit), and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA excluding net unrealized gains and losses on derivatives, lower of cost or market adjustments, gains and losses on disposal or impairment of assets, and equity-based compensation expense. We also include in Adjusted EBITDA certain inventory valuation adjustments related to our refined products and renewables segment, as described below. EBITDA and Adjusted EBITDA should not be considered alternatives to net income, income before income taxes, cash flows from operating activities, or any other measure of financial performance calculated in accordance with GAAP as those items are used to measure operating performance, liquidity or the ability to service debt obligations. We believe that EBITDA provides additional information to investors for evaluating our ability to make quarterly distributions to our unitholders and is presented solely as a supplemental measure. We believe that Adjusted EBITDA provides additional information to investors for evaluating our financial performance without regard to our financing methods, capital structure and historical cost basis. Further, EBITDA and Adjusted EBITDA, as we define them, may not be comparable to EBITDA, Adjusted EBITDA, or similarly titled measures used by other entities.

Other than for our refined products and renewables segment, for purposes of our Adjusted EBITDA calculation, we make a distinction between realized and unrealized gains and losses on derivatives. During the period when a derivative contract is open, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record a realized gain or loss. We do not

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draw such a distinction between realized and unrealized gains and losses on derivatives of our refined products and renewables segment. The primary hedging strategy of our refined products and renewables segment is to hedge against the risk of declines in the value of inventory over the course of the contract cycle, and many of the hedges are six months to one year in duration at inception. The “inventory valuation adjustment” row in the table below reflects the difference between the market value of the inventory of our refined products and renewables segment at the balance sheet date and its cost. We include this in Adjusted EBITDA because the gains and losses associated with derivative contracts of this segment, which are intended primarily to hedge inventory holding risk, also impact Adjusted EBITDA.

A portion of the revenues of our water solutions business is generated from the sale of crude oil that we recover in the process of treating the wastewater. We have historically entered into derivative contracts to protect against the risk of declines in the value of the hydrocarbons we expect to recover in future months. During the year ended March 31, 2016, we settled certain derivative contracts that related to crude oil we expect to recover in the months from April 2016 through December 2016 and realized a gain of $2.1 million. Of this gain, $0.9 million, $0.7 million and $0.5 million were attributable to derivatives with scheduled settlement dates during the quarters ending June 30, 2016, September 30, 2016, and December 31, 2016, respectively. During the year ended March 31, 2015, we settled certain derivative contracts that related to crude oil we recovered in the months from April 2015 through September 2015 and realized a gain of $17.9 million. Of this gain, $9.4 million and $8.5 million were attributable to derivatives that settled during the quarters ending June 30, 2015 and September 30, 2015, respectively.

The following table reconciles net (loss) income to our EBITDA and Adjusted EBITDA:

	Year Ended March 31,		
	2016	2015	2014
	(in thousands)		
Net (loss) income	$(187,097)	$50,193	$48,758
Less: Net income attributable to noncontrolling interests	(11,832)	(12,887)	(1,103)
Net (loss) income attributable to parent equity	(198,929)	37,306	47,655
Interest expense	126,514	106,594	58,871
Gain on early extinguishment of debt	(28,532)	—	—
Income tax (benefit) expense	(420)	(3,676)	937
Depreciation and amortization	217,893	191,998	127,821
EBITDA	116,526	332,222	235,284
Net unrealized losses (gains) on derivatives	1,255	7,559	(1,327)
Inventory valuation adjustment	24,390	—	—
Lower of cost or market adjustments	(5,932)	16,806	—
Loss on disposal or impairment of assets, net	320,783	41,274	3,597
Equity-based compensation expense (1)	58,816	42,890	17,804
Acquisition expense (2)	2,002	23,198	15,109
Revaluation of liabilities (3)	(93,725)	(20,645)	—
Adjusted EBITDA	$424,115	$443,304	$270,467

(1) Equity-based compensation expense in the table above may differ from equity-based compensation expense reported in Note 11 to our consolidated financial statements included in this Annual Report on Form 10-K (“Annual Report”). Amounts reported in the table above include expense accruals for bonuses expected to be paid in common units, whereas the amounts reported in Note 11 to our consolidated financial statements only include expenses associated with equity-based awards that have been formally granted.

(2) During the years ended March 31, 2016, 2015 and 2014, we recorded $2.0 million, $7.4 million and $6.9 million, respectively, of expense related to legal and advisory costs associated with acquisitions. During the year ended March 31, 2015, we recorded $15.8 million of compensation expense associated with acquisitions (including

certain bonuses that the previous owners of Gavilon Energy granted to employees, contingent upon the successful completion of the sale of the business, and compensation expense related to termination benefits for certain TransMontaigne Inc. (“TransMontaigne”) employees). During the year ended March 31, 2014, we recorded $8.2 million of compensation expense associated with acquisitions (including certain bonuses that the previous owners of Gavilon Energy granted to employees, contingent upon the successful completion of the sale of the business).

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(3) Amount represents the non-cash valuation adjustment of contingent consideration liabilities, offset by the cash payments, related to royalty agreements acquired as part of acquisitions in our Water Solutions segment. Amount includes $3.0 million and $0.3 million for the years ended March 31, 2016 and 2015, respectively, related to the portion attributatble to noncontrolling interests.

The following tables reconcile depreciation and amortization amounts per the EBITDA table above to depreciation and amortization amounts reported in our consolidated statements of operations and consolidated statements of cash flows for the periods indicated:

	Year Ended March 31,		
	2016	2015	2014
	(in thousands)		
Reconciliation to consolidated statements of operations:			
Depreciation and amortization per EBITDA table	$217,893	$191,998	$127,821
Intangible asset amortization recorded to cost of sales	(6,700)	(7,767)	(6,172)
Depreciation and amortization of unconsolidated entities	(20,058)	(18,979)	(1,500)
Depreciation and amortization attributable to noncontrolling interests	37,789	28,697	605
Depreciation and amortization per consolidated statements of operations	$228,924	$193,949	$120,754
Reconciliation to consolidated statements of cash flows:			
Depreciation and amortization per EBITDA table	$217,893	$191,998	$127,821
Amortization of debt issuance costs recorded to interest expense	13,587	8,759	5,727
Depreciation and amortization of unconsolidated entities	(20,058)	(18,979)	(1,500)
Depreciation and amortization attributable to noncontrolling interests	37,789	28,697	605
Depreciation and amortization per consolidated statements of cash flows	$249,211	$210,475	$132,653

The following table reconciles interest expense per the EBITDA table above to interest expense reported in our consolidated statements of operations for the periods indicated:

	Year Ended March 31,		
	2016	2015	2014
	(in thousands)		
Interest expense per EBITDA table	$126,514	$106,594	$58,871
Interest expense attributable to noncontrolling interests (1)	5,493	3,443	—
Gain on extinguishment of debt of unconsolidated entities	693	—	—
Other (2)	389	86	(17)
Interest expense per consolidated statements of operations	$133,089	$110,123	$58,854

(1) Includes ten months of consolidated TLP interest expense.
(2) Includes two months of TLP interest expense as an equity method investment.

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The following tables reconcile operating income (loss) to Adjusted EBITDA by segment for the periods indicated:

	Year Ended March 31, 2016						
	Crude Oil Logistics	Water Solutions	Liquids	Retail Propane	Refined Products and Renewables	Corporate and Other	Consolidated
	(in thousands)						
Operating (loss) income	$(40,745)	$(313,673)	$76,173	$44,096	$226,951	$(97,405)	$(104,603)
Depreciation and amortization	39,363	91,685	15,642	35,992	40,861	5,381	228,924
Amortization recorded to cost of sales	250	—	1,044	—	5,406	—	6,700
Net unrealized losses (gains) on derivatives	2,123	3,196	(4,008)	(56)	—	—	1,255
Inventory valuation adjustment	—	—	—	—	24,390	—	24,390
Lower of cost or market adjustments	(1,211)	—	—	—	(4,721)	—	(5,932)
Loss (gain) on disposal or impairment of assets, net	54,952	381,682	11,600	(137)	(127,314)	—	320,783
Equity-based compensation expense	—	—	—	—	501	58,315	58,816
Acquisition expense	—	—	—	7	—	1,995	2,002
Equity in earnings (losses) of unconsolidated entities	3,547	(552)	—	(528)	13,654	—	16,121
Other (expense) income, net	(6,725)	2,144	281	1,055	179	8,641	5,575
Depreciation and amortization of unconsolidated entities	9,927	1,135	—	98	8,898	—	20,058
Adjusted EBITDA attributable to noncontrolling interest	—	(518)	—	(1,324)	(54,407)	—	(56,249)
Revaluation of liabilities	—	(93,725)	—	—	—	—	(93,725)
Adjusted EBITDA	$61,481	$71,374	$100,732	$79,203	$134,398	$(23,073)	$424,115

	Year Ended March 31, 2015						
	Crude Oil Logistics	Water Solutions	Liquids	Retail Propane	Refined Products and Renewables	Corporate and Other	Consolidated
	(in thousands)						
Operating (loss) income	$(35,832)	$65,340	$45,072	$64,075	$54,567	$(85,802)	$107,420
Depreciation and amortization	38,626	73,618	13,513	31,827	32,948	3,417	193,949
Amortization recorded to cost of sales	102	—	1,931	—	4,057	1,677	7,767
Net unrealized losses (gains) on derivatives	7,421	(2,786)	2,921	3	—	—	7,559
Lower of cost or market adjustments	10,744	—	(51)	—	6,113	—	16,806
Loss (gain) on disposal or impairment of assets, net	3,759	7,504	29,776	330	1	(96)	41,274
Equity-based compensation expense	—	—	—	—	123	42,767	42,890
Acquisition expense	6,870	—	—	45	8,510	7,773	23,198
Equity in earnings (losses) of unconsolidated entities	3,731	(29)	—	—	8,401	—	12,103

Other income (expense), net	27,305	3,360	31	1,644	(120)	4,951	37,171
Depreciation and amortization of unconsolidated entities	10,213	1,123	—	—	7,643	—	18,979
Adjusted EBITDA attributable to noncontrolling interest	—	(1,220)	—	(1,110)	(42,837)	—	(45,167)
Revaluation of liabilities	—	(20,645)	—	—	—	—	(20,645)
Adjusted EBITDA	$72,939	$126,265	$93,193	$96,814	$ 79,406	$(25,313)	$ 443,304

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	Year Ended March 31, 2014						
	Crude Oil Logistics	Water Solutions	Liquids	Retail Propane	Refined Products and Renewables	Corporate and Other	Consolidated
	(in thousands)						
Operating income (loss)	$678	$10,317	$71,888	$61,285	$ 6,514	$(44,117)	$ 106,565
Depreciation and amortization	22,111	55,105	11,018	28,878	625	3,017	120,754
Amortization recorded to cost of sales	990	—	2,882	—	1,600	700	6,172
Net unrealized losses (gains) on derivatives	2,229	647	(4,217)	14	—	—	(1,327)
(Gain) loss on disposal or impairment of assets, net	(169)	2,994	5,305	1	—	(4,534)	3,597
Equity-based compensation expense	—	—	—	—	—	17,804	17,804
Acquisition expense	3,500	—	—	23	—	11,586	15,109
Equity in (losses) earnings of unconsolidated entities	(26)	—	—	—	—	1,924	1,898
Other (expense) income, net	(2,939)	(266)	(212)	1,308	51	2,144	86
Depreciation and amortization of unconsolidated entities	1,500	—	—	—	—	—	1,500
Adjusted EBITDA attributable to noncontrolling interest	—	(631)	—	(163)	(897)	—	(1,691)
Adjusted EBITDA	$27,874	$68,166	$86,664	$91,346	$ 7,893	$(11,476)	$ 270,467

Segment Operating Results

Items Impacting the Comparability of Our Financial Results

Our current and future results of operations may not be comparable to our historical results of operations for the periods presented, due to business combinations. We have expanded our crude oil logistics business through a number of acquisitions, including our acquisitions of Crescent Terminals, LLC and Cierra Marine, LP and its affiliated companies (collectively, “Crescent”) in July 2013, and Gavilon Energy in December 2013. We have expanded our water solutions business considerably through numerous acquisitions of water treatment and disposal facilities. We have expanded our liquids business through the February 2015 acquisition of Sawtooth. We have expanded our retail propane business through numerous acquisitions of retail propane businesses. Our refined products and renewables businesses began with our December 2013 acquisition of Gavilon Energy and significantly expanded with our July 2014 acquisition of TransMontaigne. The results of operations of our liquids and retail propane businesses are impacted by seasonality, due primarily to the increase in volumes sold during the peak heating season from October through March. In addition, product price fluctuations can have a significant impact on our sales volumes and revenues.

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Year Ended March 31, 2016 Compared to Year Ended March 31, 2015

Crude Oil Logistics

The following table summarizes the operating results of our crude oil logistics segment for the periods indicated:

	Year Ended March 31,		
	2016	2015 (1)	Change
	(in thousands, expect per barrel amounts)		
Revenues:			
Crude oil sales	$3,170,891	$6,621,871	$(3,450,980)
Crude oil transportation and other	55,882	43,349	12,533
Total revenues (2)	3,226,773	6,665,220	(3,438,447)
Expenses:			
Cost of sales	3,121,411	6,590,313	(3,468,902)
Operating expenses	43,458	52,790	(9,332)
General and administrative expenses	8,334	15,564	(7,230)
Depreciation and amortization expense	39,363	38,626	737
Loss on disposal or impairment of assets, net	54,952	3,759	51,193
Total expenses	3,267,518	6,701,052	(3,433,534)
Segment operating loss (3)	$(40,745)	$(35,832)	$(4,913)
Crude oil sold (barrels)	67,211	83,864	(16,653)
Crude oil sold ($/barrel)	$47.178	$78.960	$(31.782)
Cost per crude oil sold ($/barrel)	$46.442	$78.583	$(32.141)
Crude oil product margin ($/barrel)	$0.736	$0.377	$0.359

(1) During the six months ended September 30, 2015, we made certain changes in the way we attribute revenues to the categories shown in the table above. These changes did not impact total revenues. We have retrospectively adjusted previously reported amounts to conform to the current presentation.

(2) Revenues include $9.7 million and $29.8 million of intersegment sales during the years ended March 31, 2016 and 2015, respectively, that are eliminated in our consolidated statements of operations.

(3) In October 2014, we announced plans to build a crude oil rail transloading facility, backed by executed producer commitments. Subsequent to executing these commitments, the producers requested to be released from the commitments. We agreed to release the producers from their commitments in return for a cash payment in March 2015 and additional cash payments over the next five years. Upon execution of these agreements in March 2015, we recorded a gain of $31.6 million to other income in our consolidated statement of operations, net of certain project abandonment costs. Since this gain was reported in other income, it is not reflected in the table above.

Crude Oil Sales. The decrease in revenue per barrel was due primarily to the sharp decline in crude oil prices since July 2014. The decrease in our sales volumes was due primarily to a slowdown in crude oil production and new drilling of crude oil in the current crude oil price environment.

Our cost of sales during the year ended March 31, 2016 was increased by $2.1 million of net unrealized losses on derivatives and reduced by $13.8 million of net realized gains on derivatives. Our cost of sales during the year ended March 31, 2015 was increased by $7.4 million of net unrealized losses on derivatives and reduced by $37.4 million of net realized gains on derivatives. Due to the sharper decline in crude oil prices during the year ended March 31, 2015 compared to the year ended March 31, 2016, realized gains on derivatives were higher during the year ended March 31, 2015. Our cost of sales during the year ended March 31, 2015 was also impacted by a lower of cost or market adjustment of $10.7 million recorded at March 31, 2015.

Crude Oil Transportation and Other Revenues. The increase was due primarily to crude oil markets being in contango during the year ended March 31, 2016 (a condition in which forward crude oil prices are greater than spot prices), which allowed us to generate revenue from leasing our owned storage and subleasing our leased storage.

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Operating Expenses. The decrease was due primarily to lower compensation expense due primarily to a reduction in headcount from organizational changes and lower repair and maintenance expense due to the timing of repairs.

General and Administrative Expenses. The decrease was due primarily to $5.6 million of compensation expense during the year ended March 31, 2015 related to bonuses that the previous owners of Gavilon Energy granted to employees, contingent upon successful completion of the sale of the business, which were paid in December 2014, and $1.3 million of compensation expense during the year ended March 31, 2015 related to termination benefits for certain TransMontaigne employees.

Depreciation and Amortization Expense. The increase was due primarily to capital additions during the year ended March 31, 2016.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2016, we recorded a write-down of $47.7 million related to pipe we no longer expect to use in the originally-planned Grand Mesa Pipeline. Also, during the year ended March 31, 2016, (i) two previously-planned projects were canceled and we recorded a loss of $3.1 million, (ii) we recorded an impairment of $2.4 million to the property, plant and equipment of two of our crude oil barges and (iii) we sold and/or abandoned certain trucks, trailers and barges and recorded a loss of $1.4 million. During the year ended March 31, 2015, we recorded a write-off of project costs of $3.5 million related to a crude oil terminal project that has been discontinued.

Water Solutions

The following table summarizes the operating results of our water solutions segment for the periods indicated:

	Year Ended March 31,		
	2016	2015	Change
	(in thousands, except per barrel amounts)		
Revenues:			
Service fees	$136,710	$105,682	$31,028
Recovered hydrocarbons	41,090	81,762	(40,672)
Water transportation	—	10,760	(10,760)
Other revenues	7,201	1,838	5,363
Total revenues	185,001	200,042	(15,041)
Expenses:			
Cost of sales-derivative gain (1)	(7,095)	(36,763)	29,668
Cost of sales-other	(241)	6,257	(6,498)
Operating expenses	112,538	93,268	19,270
General and administrative expenses	2,778	3,082	(304)
Depreciation and amortization expense	91,685	73,618	18,067
Loss on disposal or impairment of assets, net	381,682	7,504	374,178
Revaluation of liabilities	(82,673)	(12,264)	(70,409)
Total expenses	498,674	134,702	363,972
Segment operating (loss) income	$(313,673)	$65,340	$(379,013)
Water received (barrels)	208,440	161,664	46,776
Service fee for water processed ($/barrel)	$0.66	$0.65	$0.01
Recovered hydrocarbons for water processed ($/barrel)	$0.20	$0.51	$(0.31)

(1) Includes realized and unrealized (gains) losses.

The following tables summarize activity separated between the following categories:

- facilities we owned before March 31, 2014, which we refer to below as “existing facilities”; and
- facilities we acquired or developed after March 31, 2014, which we refer to below as “recently acquired or developed facilities”.

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Service Fee Revenues. The following table summarizes our service fee revenues (in thousands, except per barrel amounts) for the periods indicated:

	Year Ended March 31,					
	2016			2015		
	Service Fees	Water Barrels Processed	Fees Per Water Barrel Processed	Service Fees	Water Barrels Processed	Fees Per Water Barrel Processed
Existing facilities	$74,195	90,377	$ 0.82	$81,273	122,454	$ 0.66
Recently acquired or developed facilities	62,515	118,063	0.53	24,409	39,210	0.62
Total	$136,710	208,440	0.66	$105,682	161,664	0.65

The decrease in the volume processed at our existing facilities was due primarily to a slowdown in customer production as a result of the lower crude oil prices, as well as migration of volumes from existing facilities to recently developed or acquired facilities due to the location of the new facilities. The increase in fees per water barrel processed at our existing facilities is partially due to an increase in the service fees in a certain basin and a favorable deliver or pay agreement with a customer where the customer has not been delivering water to our facilities.

Recovered Hydrocarbon Revenues. The following table summarizes our recovered hydrocarbon revenues (in thousands, except per barrel amounts) for the periods indicated:

	Year Ended March 31,					
	2016			2015		
	Recovered Hydrocarbon Revenue	Water Barrels Processed	Revenue Per Water Barrel Processed	Recovered Hydrocarbon Revenue	Water Barrels Processed	Revenue Per Water Barrel Processed
Existing facilities	$22,791	90,377	$ 0.25	$71,301	122,454	$ 0.58
Recently acquired or developed facilities	18,299	118,063	0.15	10,461	39,210	0.27
Total	$41,090	208,440	0.20	$81,762	161,664	0.51

The decrease in revenue per barrel associated with recovered hydrocarbons was due primarily to the sharp decline in crude oil prices since July 2014 and a decrease in the volume of hydrocarbons recovered per barrel of water processed.

Water Transportation Revenues. The decrease was due to revenues related to our water transportation business during the year ended March 31, 2015. We sold this business during September 2014.

Other Revenues. The increase was due primarily to revenues related to the disposal of solids.

Cost of Sales. We enter into derivatives in our water solutions segment to protect against the risk of a decline in the market price of the hydrocarbons we expected to recover when processing the wastewater. Our cost of sales during the year ended March 31, 2016 included $10.3 million of net realized gains on derivatives, partially offset by $3.2 million of net unrealized losses on derivatives. Our cost of sales during the year ended March 31, 2015 included $2.8 million of net unrealized gains on derivatives and $34.0 million of net realized gains on derivatives. In December 2015, we settled derivative contracts that had scheduled settlement dates from January 2016 through December 2016, in order to lock in the gains on those derivatives. In December 2014, we settled derivative contracts that had scheduled settlement dates from April 2015 through September 2015, in order to lock in the gains on those derivatives.

The decrease in other cost of sales was due to costs related to our water transportation business during the year ended March 31, 2015. We sold this business during September 2014.

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Operating Expenses. The following table summarizes our operating expenses for the periods indicated:

	Year Ended March 31,		
	2016	2015	Change
	(in thousands)		
Existing facilities	$65,739	$73,533	$(7,794)
Recently acquired or developed facilities	46,799	19,735	27,064
Total	$112,538	$93,268	$19,270

The decrease in operating expenses for existing facilities was due primarily to lower operating costs of water disposal wells at existing facilities due to lower volumes processed.

Depreciation and Amortization Expense. Of the increase, $15.7 million related to recently acquired or developed water treatment and disposal facilities and $3.4 million related to recently developed solids processing facilities.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2016, we recorded an estimated goodwill impairment charge of $380.2 million as the decline in crude oil prices and crude oil production have had an unfavorable impact on our water solutions business (see Note 14 to our consolidated financial statements included in this Annual Report). During the year ended March 31, 2015, we sold our water transportation business and recorded a loss of $4.0 million. Also, during the year ended March 31, 2015, we recorded a loss on abandonment of $3.1 million related to property, plant and equipment of water disposal facilities that we have retired.

Revaluation of Liabilities. The revaluation of liabilities represents the valuation adjustment of contingent consideration liabilities related to royalty agreements acquired as part of certain business combinations. The increase was due to additional acquisitions during the year ended March 31, 2016 offset by changes in the fair value of the liability.

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Liquids

The following table summarizes the operating results of our liquids segment for the periods indicated:

	Year Ended March 31,		
	2016	2015 (1)	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues (2)	$618,919	$1,265,262	$(646,343)
Cost of sales	571,734	1,217,993	(646,259)
Product margin	47,185	47,269	(84)
Other product sales:			
Revenues (2)	620,175	1,111,834	(491,659)
Cost of sales	532,136	1,038,324	(506,188)
Product margin	88,039	73,510	14,529
Other revenues:			
Revenues (2)	35,943	28,745	7,198
Cost of sales	13,806	17,313	(3,507)
Product margin	22,137	11,432	10,705
Expenses:			
Operating expenses	45,140	35,580	9,560
General and administrative expenses	8,806	8,271	535
Depreciation and amortization expense	15,642	13,513	2,129
Loss on disposal or impairment of assets, net	11,600	29,775	(18,175)
Total expenses	81,188	87,139	(5,951)
Segment operating income	$76,173	$45,072	$31,101
Propane sold	1,244,529	1,285,707	(41,178)
Propane sold ($/gallon)	$0.497	$0.984	$(0.487)
Cost per propane sold ($/gallon)	$0.459	$0.947	$(0.488)
Propane product margin ($/gallon)	$0.038	$0.037	$0.001
Other products sold (gallons)	843,922	825,514	18,408
Other products sold ($/gallon)	$0.735	$1.347	$(0.612)
Cost per other products sold ($/gallon)	$0.631	$1.258	$(0.627)
Other products product margin ($/gallon)	$0.104	$0.089	$0.015

(1) During the six months ended September 30, 2015, we made certain changes in the way we attribute revenues to railcar cost of sales to the categories shown in the table above. These changes did not impact total revenues or total cost of sales. We have retrospectively adjusted previously reported amounts to conform to the current presentation.

(2) Revenues include $80.6 million and $162.0 million of intersegment sales during the years ended March 31, 2016 and 2015, respectively, that are eliminated in our consolidated statements of operations.

Propane Sales. The decrease in volumes was due to significantly warmer temperatures in the current year. The decrease in selling price was due to lower commodity prices from oversupply in the market and decreased demand due to the significantly warmer temperatures in the current year winter.

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Our cost of wholesale propane sales was reduced by $2.1 million of net unrealized gains on derivatives and increased by $4.6 million of net unrealized losses on derivatives for the years ended March 31, 2016 and 2015, respectively. Additionally, our cost of wholesale propane sales was increased by $1.6 million of net realized losses on derivatives and $8.2 million of net realized losses on derivatives for the years ended March 31, 2016 and 2015, respectively.

Product margins per gallon of propane sold were higher during the year ended March 31, 2016 than during the year ended March 31, 2015. Propane prices declined during the year ended March 31, 2016, but not as sharply as they declined during the year ended March 31, 2015. Declining propane prices typically have an adverse effect on our margins.

We use a weighted-average inventory costing method for our wholesale propane inventory, with the costing pools segregated based on the location of the inventory. One of our business strategies is to purchase and store inventory during the warmer months for sale during the winter months. We seek to lock in a margin on inventory held in storage through back-to-back purchases and sales, fixed-price forward sale commitments, and financial derivatives. We also have contracts whereby we have committed to purchase ratable volumes each month at index prices. We seek to manage the price risk associated with these contracts primarily by selling the inventory immediately after it is received. When we sell product, we record the cost of the sale at average cost of all inventory at that location, which may include inventory stored for sale in the future. During periods of rising prices, this can result in greater margins on these sales. During periods of declining prices, this can result in lower margins on these sales. We would generally expect the impact of these two different strategies being in the same inventory costing pools to even out over the course of a full fiscal year.

Other Products Sales. The increase in the volume of other wholesale products sold was due to expanded operations.

Our cost of sales of other products during the year ended March 31, 2016 was reduced by $1.9 million of net unrealized gains on derivatives. Our cost of sales of other products during the year ended March 31, 2015 was reduced by $1.7 million of net unrealized gains on derivatives. Additionally, our cost of other products was reduced by $1.8 million of net realized gains on derivatives and increased by $5.4 million of net realized losses on derivatives for the years ended March 31, 2016 and 2015, respectively.

Product margins during the year ended March 31, 2016 benefited from a high level of butane supply in the market, which lowered our product cost.

Other Revenues. This revenue includes storage, terminaling and transportation services income. The increase was due primarily to $21.1 million of revenue related to Sawtooth, which we acquired in February 2015, partially offset by a $10.0 million decrease in hauling revenues due to declining market conditions.

Operating Expenses. The increase was due primarily to $4.6 million of expenses related to Sawtooth, which we acquired in February 2015, as well as a shift in the recording of incentive compensation expense related to bonuses from the liquids segment to “corporate and other” during the year ended March 31, 2015. See further discussion within the “Corporate and Other” section below.

General and Administrative Expenses. The increase was due primarily to $1.4 million of expenses related to Sawtooth, which we acquired in February 2015.

Depreciation and Amortization Expense. The increase was due to an additional $4.2 million of expense during the year ended March 31, 2016 related to Sawtooth, which we acquired in February 2015, partially offset by $1.0 million of expense recorded during the year ended March 31, 2015 related to a natural gas liquids terminal that we sold in December 2014.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2016, we wrote off assets of $14.6 million acquired as part of the Gavilon Energy acquisition that we deemed no longer recoverable. During the year ended March 31, 2016, we received a payment of $3.0 million from the state of Maine to relocate certain terminal assets. During the year ended March 31, 2015, we recorded a loss on disposal of assets of $29.8 million related to the sale of a natural gas liquids terminal.

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Retail Propane

The following table summarizes the operating results of our retail propane segment for the periods indicated:

	Year Ended March 31,		
	2016	2015	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues	$248,673	$347,575	$(98,902)
Cost of sales	95,191	181,655	(86,464)
Product margin	153,482	165,920	(12,438)
Distillate sales:			
Revenues	64,868	106,037	(41,169)
Cost of sales	48,191	85,329	(37,138)
Product margin	16,677	20,708	(4,031)
Other revenues:			
Revenues	39,436	35,585	3,851
Cost of sales	13,375	11,554	1,821
Product margin	26,061	24,031	2,030
Expenses:			
Operating expenses	104,287	102,123	2,164
General and administrative expenses	11,982	12,352	(370)
Depreciation and amortization expense	35,992	31,827	4,165
(Gain) loss on disposal or impairment of assets, net	(137)	282	(419)
Total expenses	152,124	146,584	5,540
Segment operating income	$44,096	$64,075	$(19,979)
Propane sold (gallons)	152,238	169,279	(17,041)
Propane sold ($/gallon)	$1.633	$2.053	$(0.420)
Cost per propane sold ($/gallon)	$0.625	$1.073	$(0.448)
Propane product margin ($/gallon)	$1.008	$0.980	$0.028
Distillates sold (gallons)	30,674	34,862	(4,188)
Distillates sold ($/gallon)	$2.115	$3.042	$(0.927)
Cost per distillates sold ($/gallon)	$1.571	$2.448	$(0.877)
Distillates product margin ($/gallon)	$0.544	$0.594	$(0.050)

Revenues. The decrease in both propane and distillate revenues was due to lower volumes as a result of significantly warmer winter temperatures in the current year, as compared to the prior year. The decrease in selling price was due to an oversupply in the propane market lowering commodity prices as well as the significantly warmer temperatures in the current year winter.

Cost of Sales. Cost of sales decreased for both propane and distillates due to lower commodity prices.

Operating Expenses. The increase was due primarily to increased compensation associated with acquisitions of retail propane businesses.

General and Administrative Expenses. Our retail propane segment general and administrative expenses for the year ended March 31, 2016 were consistent with those of the prior year with the exception of bad debt expense which was lower due to lower sales.

Depreciation and Amortization Expense. The increase was due primarily to acquisitions of retail propane businesses.

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Refined Products and Renewables

The following table summarizes the operating results of our refined products and renewables segment for the periods indicated. Our refined products and renewables segment was significantly expanded with our July 2014 acquisition of TransMontaigne. On February 1, 2016, we sold our general partner interest in TLP. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting.

	Year Ended March 31,		
	2016	2015 (1)	Change
	(in thousands, except per barrel and gallon amounts)		
Refined products sales:			
Revenues (2)	$6,294,008	$6,682,040	$(388,032)
Cost of sales	6,161,243	6,574,545	(413,302)
Product margin	132,765	107,495	25,270
Renewables sales:			
Revenues	390,753	473,885	(83,132)
Cost of sales	380,212	461,996	(81,784)
Product margin	10,541	11,889	(1,348)
Service fee revenues	108,221	76,847	31,374
Expenses:			
Operating expenses	95,371	82,583	12,788
General and administrative expenses	15,675	26,133	(10,458)
Depreciation and amortization expense	40,861	32,948	7,913
Gain on disposal or impairment of assets, net	(127,331)	—	(127,331)
Total expenses	24,576	141,664	(117,088)
Segment operating income	$226,951	$54,567	$172,384
Refined products sold (barrels)	98,988	68,043	30,945
Refined products sold ($/barrel)	$63.584	$98.203	$(34.619)
Cost per refined products sold ($/barrel)	$62.242	$96.623	$(34.381)
Refined products product margin ($/barrel)	$1.342	$1.580	$(0.238)
Refined products product margin ($/gallon)	$0.032	$0.038	$(0.006)
Renewable products sold (barrels)	5,794	5,318	476
Renewable products sold ($/barrel)	$67.441	$89.110	$(21.669)
Cost per renewable products sold ($/barrel)	$65.622	$86.874	$(21.252)
Renewable products product margin ($/barrel)	$1.819	$2.236	$(0.417)
Renewable products product margin ($/gallon)	$0.043	$0.053	$(0.010)

(1) During the six months ended September 30, 2015, we made certain changes in the way we attribute revenues and cost of sales to the categories shown in the table above. These changes did not impact total revenues or total cost of sales. We have retrospectively adjusted previously reported amounts to conform to the current presentation.

(2) Revenues include $0.9 million and $1.1 million of intersegment sales during the years ended March 31, 2016, and 2015, respectively, that are eliminated in our consolidated statement of operations.

Refined Products and Renewables Sales. Our refined products and renewables segment was significantly expanded with our July 2014 acquisition of TransMontaigne. The resultant increase in revenues and cost of sales was offset by a sharp decline in product prices. Also, the decrease in per-barrel renewable product margins was due primarily to lower renewables

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prices caused by increased import activity, partially offset by an increase in the amount we can claim for certain biodiesel tax credits from $5.8 million for transactions during calendar year 2014 to $6.2 million for transactions in calendar year 2015.

Operating Expenses. The increase was due primarily to the inclusion of TLP for ten months of the current fiscal year, compared to nine months of the prior fiscal year as TLP was deconsolidated on February 1, 2016. Also contributing to the increase was the inclusion of TransMontaigne for the entire current fiscal year, compared to nine months of the prior fiscal year.

General and Administrative Expenses. The decrease was due primarily to $8.0 million of compensation expense during the year ended March 31, 2015 related to termination benefits for certain TransMontaigne employees. This decrease was partially offset by the inclusion of TransMontaigne for the entire current fiscal year, compared to nine months of the prior fiscal year.

Depreciation and Amortization Expense. The increase was due primarily to the inclusion of TLP for ten months of the current fiscal year, compared to nine months of the prior fiscal year as TLP was deconsolidated on February 1, 2016.

Gain on Disposal or Impairment of Assets, Net. During the year ended March 31, 2016, we sold our general partner interest in TLP and recorded a gain on disposal of $329.9 million during the three months ended March 31, 2016. As part of this transaction, we entered into lease agreements whereby we will remain the long-term exclusive tenant in the TLP Southeast terminal system. As a result of entering into these leases, we deferred $204.6 million of the gain on the sale and will recognize this amount over our future lease payment obligations, which is approximately seven years. During the three months ended March 31, 2016, we recognized $5.0 million of the deferred gain in our consolidated statement of operations. See "Recent Developments" above for a further discussion. During the year ended March 31, 2016, we recorded a loss of $1.8 million related to certain property, plant and equipment that we have retired and we also sold certain tank bottoms and recorded a loss of $1.3 million.

Corporate and Other

The operating loss within "corporate and other" includes the following components for the periods indicated:

	Year Ended March 31,		
	2016	2015	Change
	(in thousands)		
Incentive compensation expense	$(61,252)	$(48,339)	$(12,913)
Acquisition expense	(2,002)	(7,382)	5,380
Other corporate expenses	(34,151)	(30,081)	(4,070)
Total	$(97,405)	$(85,802)	$(11,603)

The expenses shown in the table above for incentive compensation include cash-based and equity-based compensation. Such incentive compensation expenses were higher during the year ended March 31, 2016 than during the year ended March 31, 2015, due primarily to two factors described below.

As part of its review of our executive compensation program, the Compensation Committee of the Board of Directors approved a new type of equity-based compensation award, under which the number of common units that vest is contingent upon the performance of our common units relative to the performance of other entities in the Alerian MLP Index. During the year ended March 31, 2016, three tranches of these Performance Awards were granted, with vesting dates of July 1, 2015, July 1, 2016, and July 1, 2017, respectively. We recorded $16.4 million of expense related to the Performance Awards during the year ended March 31, 2016, $16.1 million of which related to awards that vested on July 1, 2015.

We have also granted certain Service Awards, which vest contingent only on the continued service of the recipients. The number of outstanding Service Awards was higher at March 31, 2016 than at March 31, 2015. This was due in part to the addition of new employees as our business has expanded, and was due in part to increases in the number of Service Awards granted to certain employees following the Compensation Committee's review of our compensation program. The expense associated with these Service Awards (exclusive of accruals of annual bonuses paid or expected to be paid in common units) was $35.2 million during the year ended March 31, 2016, compared to $32.8 million during the year ended March 31, 2015.

The expense associated with annual bonuses (a portion of which were paid or are expected to be paid in common units) was $2.9 million during the year ended March 31, 2016, compared to $5.0 million during the year ended March 31, 2015.

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We record compensation expense related to common units within “corporate and other”, while compensation expense paid in cash is recorded within the individual business segments.

The expenses shown in the table above for acquisitions relate primarily to legal and advisory costs. We incurred $4.2 million of such expenses during the year ended March 31, 2015 related to our acquisition of TransMontaigne.

Equity in Earnings of Unconsolidated Entities

Equity in earnings of unconsolidated entities was $16.1 million and $12.1 million during the years ended March 31, 2016 and 2015, respectively. The increase was due primarily to an increase of $7.1 million of earnings from TLP (including Battleground Oil Specialty Terminal Company LLC (“BOSTCO”) and Frontera Brownsville LLC (“Frontera”)) that we acquired as part of our July 2014 acquisition of TransMontaigne, and which we deconsolidated when we sold our general partner interest in TLP as of February 1, 2016, partially offset by a decrease of $2.4 million in earnings from our investments in an ethanol production facility and a water supply company.

Interest Expense

Interest expense includes interest expense on our revolving credit facilities and senior notes, amortization of debt issuance costs, letter of credit fees, interest on equipment financing notes, and accretion of interest on noninterest bearing debt obligations. Interest expense was $133.1 million and $110.1 million during the years ended March 31, 2016 and 2015, respectively. The increase in interest expense was due primarily to (i) the increased level of debt outstanding on our Revolving Credit Facility (the average balance outstanding on our Revolving Credit Facility was $1.7 billion during the year ended March 31, 2016, compared to $1.2 billion during year ended March 31, 2015), primarily to finance acquisitions and capital expenditures; (ii) the issuance of $400.0 million of fixed-rate notes during July 2014; and (iii) increased interest expense related to TLP’s credit facility (our interest in TLP was acquired in July 2014, and we sold our general partner interest in TLP as of February 1, 2016).

Gain on Early Extinguishment of Debt

During the fourth quarter of fiscal year 2016, we repurchased $73.2 million of our 2019 Notes and 2021 Notes for an aggregate purchase price of $43.4 million (excluding payments of accrued interest). As a result, we recorded a gain on the early extinguishment of our 2019 Notes and 2021 Notes of $28.5 million (net of the write off of debt issuance costs of $1.3 million).

Other Income, Net

The following table summarizes the components of other income, net for the periods indicated:

	Year Ended March 31,	
	2016	2015
	(in thousands)	
Interest income (1)	$ 12,004	$ 4,575
Crude oil marketing arrangement (2)	(6,726)	(5,642)
Crude oil rail transloading facility (3)	—	31,600
Other (4)	297	6,638
Other income, net	$ 5,575	$ 37,171

(1)

Relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility to be utilized by a third party and to a loan receivable from an equity method investee.

(2) Represents another party's share of the profits generated from a joint crude oil marketing arrangement.

(3) In October 2014, we announced plans to build a crude oil rail transloading facility, backed by executed producer commitments. Subsequent to executing these commitments, the producers requested to be released from the commitments. We agreed to release the producers from their commitments in return for a cash payment in March 2015 and additional cash payments over the next five years. In addition, one of the producers committed to pay us a specified fee on each barrel

of crude oil it produces in a specified basin over a period of seven years. Upon execution of these agreements in March 2015, we recorded a gain of $31.6 million to other income, net of certain project abandonment costs.

(4) During the year ended March 31, 2015, we settled two separate contractual disputes and recorded $5.5 million of proceeds to other income. Also during the year ended March 31, 2015, we offered to settle another contractual dispute, and recorded $1.2 million to other expense as an estimate of the probable loss. During the year ended March 31, 2016, we finalized the settlement of this contractual dispute and paid approximately $0.5 million at the date of settlement and committed to pay approximately $1.1 million in equal annual installments over a period of 11 years beginning on October 15, 2016 and ending in October 2026.

Income Tax Expense (Benefit)

We qualify as a partnership for income tax purposes. As such, we generally do not pay United States federal income tax. Rather, each owner reports his or her share of our income or loss on his or her individual tax return. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined, as we do not have access to information regarding each partner’s basis in the Partnership.

We have certain taxable corporate subsidiaries in the United States and in Canada, and our operations in Texas are subject to a state franchise tax that is calculated based on revenues net of cost of sales. Our fiscal years 2012 to 2015 generally remain subject to examination by federal, state, and Canadian tax authorities. We utilize the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply in the years in which these temporary differences are expected to be recovered or settled. Changes in tax rates are recognized in income in the period that includes the enactment date.

Income tax benefit was $0.4 million and $3.6 million during the years ended March 31, 2016 and 2015, respectively. TransMontaigne was a taxable subsidiary from July 1, 2014 (the date we acquired TransMontaigne) to December 30, 2014 (the date we converted TransMontaigne to a non-taxable entity). Income tax benefit during the year ended March 31, 2016 includes a benefit of $3.6 million related to a change in estimate of the income tax obligation payable related to TransMontaigne. Income tax benefit during the year ended March 31, 2015 was attributable primarily to TransMontaigne.

Noncontrolling Interests

We have certain consolidated subsidiaries in which outside parties own interests. The noncontrolling interest shown in our consolidated financial statements represents the other owners’ interest in these entities.

Net income attributable to noncontrolling interests was $11.8 million and $12.9 million during the years ended March 31, 2016 and 2015, respectively. The noncontrolling interests were due primarily to the July 2014 acquisition of TransMontaigne, in which we acquired the 2% general partner interest and a 19.7% limited partner interest in TLP. On February 1, 2016, we sold our general partner interest in TLP. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting.

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Year Ended March 31, 2015 Compared to Year Ended March 31, 2014

Crude Oil Logistics

The following table summarizes the operating results of our crude oil logistics segment for the periods indicated:

	Year Ended March 31,		
	2015	2014	Change
	(in thousands, expect per barrel amounts)		
Revenues:			
Crude oil sales	$6,621,871	$4,559,923	$2,061,948
Crude oil transportation and other	43,349	36,469	6,880
Total revenues (1)	6,665,220	4,596,392	2,068,828
Expenses:			
Cost of sales	6,590,313	4,515,244	2,075,069
Operating expenses	52,790	54,043	(1,253)
General and administrative expenses	15,564	4,487	11,077
Depreciation and amortization expense	38,626	22,111	16,515
Loss (gain) on disposal or impairment of assets, net	3,759	(171)	3,930
Total expenses	6,701,052	4,595,714	2,105,338
Segment operating (loss) income (2)	$(35,832)	$678	$(36,510)
Crude oil sold (barrels)	83,864	46,107	37,757
Crude oil sold ($/barrel)	$78.960	$98.899	$(19.939)
Cost per crude oil sold ($/barrel)	$78.583	$97.930	$(19.347)
Crude oil product margin ($/barrel)	$0.377	$0.969	$(0.592)

(1) Revenues include $29.8 million and $37.8 million of intersegment sales during the years ended March 31, 2015 and 2014, respectively, that are eliminated in our consolidated statements of operations.

(2) In October 2014, we announced plans to build a crude oil rail transloading facility, backed by executed producer commitments. Subsequent to executing these commitments, the producers requested to be released from the commitments. We agreed to release the producers from their commitments in return for a cash payment in March 2015 and additional cash payments over the next five years. Upon execution of these agreements in March 2015, we recorded a gain of $31.6 million to other income in our consolidated statement of operations, net of certain project abandonment costs. Since this gain was reported in other income, it is not reflected in the table above.

Crude Oil Sales. The decrease in revenue per barrel was due primarily to the sharp decline in crude oil prices since July 2014. The most significant driver of the increase in our sales volumes was the acquisition of Gavilon Energy in December 2013.

Our cost of sales during the year ended March 31, 2015 was increased by $7.4 million of net unrealized losses on derivatives and reduced by $37.4 million of net realized gains on derivatives. Our cost of sales during the year ended March 31, 2014 was increased by $2.2 million of net unrealized losses on derivatives and $5.1 million of net realized losses on derivatives.

The decrease in product margins was due primarily to the sharp decline in crude oil prices since July 2014, which had an adverse impact on margins due to the difference in timing of when we purchase product and when we deliver it to the point of sale. In addition, we were unable to utilize certain leased storage during most of the year ended March 31, 2015, as crude oil markets were backwardated for most of the year.

Crude Oil Transportation and Other Revenues. The increase was due primarily to the Crescent acquisition in July 2013 and the Gavilon Energy acquisition in December 2013.

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Operating Expenses. The decrease was due primarily to a shift in the recording of incentive compensation expense related to bonuses from the crude oil logistics segment to “corporate and other” during the year ended March 31, 2015. See further discussion within the “Corporate and Other” section below. The decrease was also due to lower railcar lease expense as we purchased railcars beginning in January 2014 to utilize in our operations and lower relocation expenses, partially offset by an increase due to the Gavilon Energy acquisition in December 2013.

General and Administrative Expenses. The increase was due to the acquisitions of Gavilon Energy in December 2013 and TransMontaigne in July 2014. General and administrative expenses during the years ended March 31, 2015 and 2014 were increased by $5.6 million and $3.0 million, respectively, of compensation expense related to bonuses that the previous owners of Gavilon Energy granted to employees, contingent upon successful completion of the sale of the business. These bonuses were paid in December 2014. General and administrative expenses during the year ended March 31, 2015 were also increased by $1.3 million of compensation expense related to termination benefits for certain TransMontaigne employees.

Depreciation and Amortization Expense. The increase was due primarily to acquisitions and capital expansions.

Loss (Gain) on Disposal or Impairment of Assets, Net. During the year ended March 31, 2015, we recorded a write-off of project costs of $3.5 million related to a crude oil terminal project that has been discontinued.

Water Solutions

The following table summarizes the operating results of our water solutions segment for the periods indicated:

	Year Ended March 31,		
	2015	2014	Change
	(in thousands, except per barrel amounts)		
Revenues:			
Service fees	$105,682	$58,161	$47,521
Recovered hydrocarbons	81,762	67,627	14,135
Water transportation	10,760	17,312	(6,552)
Other revenues	1,838	—	1,838
Total revenues	200,042	143,100	56,942
Expenses:			
Cost of sales-derivative (gain) loss (1)	(36,763)	1,969	(38,732)
Cost of sales-other	6,257	9,769	(3,512)
Operating expenses	93,268	59,184	34,084
General and administrative expenses	3,082	3,762	(680)
Depreciation and amortization expense	73,618	55,105	18,513
Loss on disposal or impairment of assets, net	7,504	2,994	4,510
Revaluation of liabilities	(12,264)	—	(12,264)
Total expenses	134,702	132,783	1,919
Segment operating income	$65,340	$10,317	$55,023
Water received (barrels)	161,664	75,451	86,213
Service fee for water processed ($/barrel)	$0.65	$0.77	$(0.12)
Recovered hydrocarbons for water processed ($/barrel)	$0.51	$0.90	$(0.39)

(1) Includes realized and unrealized (gains) losses.

The following tables summarize activity separated between the following categories:

- facilities we owned before March 31, 2013, which we refer to below as “existing facilities”; and
- facilities we acquired or developed after March 31, 2013, which we refer to below as “recently acquired or developed facilities”.

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Service Fee Revenues. The following table summarizes our service fee revenues (in thousands, except per barrel amounts) for the periods indicated:

	Year Ended March 31,					
	2015			2014		
	Service Fees	Water Barrels Processed	Fees Per Water Barrel Processed	Service Fees	Water Barrels Processed	Fees Per Water Barrel Processed
Existing facilities	$65,541	85,560	$ 0.77	$51,908	59,305	$ 0.88
Recently acquired or developed facilities	40,141	76,104	0.53	6,253	16,146	0.39
Total	$105,682	161,664	0.65	$58,161	75,451	0.77

The increase in the volume processed at our existing facilities was due primarily to increased demand from customers. Also, the average revenue per barrel varies across the areas in which we operate due to market conditions in these areas. Per-barrel revenues are highest at our facility in Wyoming due to the nature of the services required. The majority of the recently acquired facilities are in Texas, where market rates for disposal are lower.

Recovered Hydrocarbon Revenues. The following table summarizes our recovered hydrocarbon revenues (in thousands, except per barrel amounts) for the periods indicated:

	Year Ended March 31,					
	2015			2014		
	Recovered Hydrocarbon Revenue	Water Barrels Processed	Revenue Per Water Barrel Processed	Recovered Hydrocarbon Revenue	Water Barrels Processed	Revenue Per Water Barrel Processed
Existing facilities	$36,361	85,560	$ 0.42	$40,393	59,305	$ 0.68
Recently acquired or developed facilities	45,401	76,104	0.60	27,234	16,146	1.69
Total	$81,762	161,664	0.51	$67,627	75,451	0.90

The decrease in revenue per barrel associated with recovered hydrocarbons was due primarily to the sharp decline in crude oil prices since July 2014.

Water Transportation Revenues. The decrease resulted from the sale of our water transportation business during September 2014.

Cost of Sales. We enter into derivatives in our water solutions segment to protect against the risk of a decline in the market price of the hydrocarbons we expected to recover when processing the wastewater. Our cost of sales during the year ended March 31, 2015 included $2.8 million of net unrealized gains on derivatives and $34.0 million of net realized gains on derivatives. Our cost of sales during the year ended March 31, 2014 included $0.6 million of net unrealized losses on derivatives and $1.4 million of net realized losses on derivatives. In December 2014, we settled derivative contracts that had scheduled settlement dates from April 2015 through September 2015, in order to lock in the gains on those derivatives.

The decrease in other cost of sales resulted from the sale of our water transportation business during September 2014.

Operating Expenses. The following table summarizes our operating expenses for the periods indicated:

	Year Ended March 31,		
	2015	2014	Change
	(in thousands)		
Existing facilities	$41,167	$36,381	$4,786

Recently acquired or developed facilities	52,101	22,803	29,298
Total	$93,268	$59,184	$34,084

The increase in operating expenses for existing facilities was due primarily to increased costs associated with the construction and operation of new water disposal wells at existing facilities.

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Depreciation and Amortization Expense. Of this increase, $15.0 million related to acquisitions, which included $1.3 million of amortization expense related to trade name intangible assets. The remaining increase was due primarily to $1.8 million of amortization expense related to trade name intangible assets. During the fourth quarter of the year ended March 31, 2014, we ceased using certain trade names and began amortizing them as finite-lived defensive assets.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2015, we sold our water transportation business and recorded a loss of $4.0 million. Also, during the year ended March 31, 2015, we recorded a loss on abandonment of $3.1 million related to property, plant and equipment of water disposal facilities that we have retired. During the year ended March 31, 2014, we recorded losses on disposal of property, plant and equipment of $2.0 million as a result of property damage from lightning strikes at two of our facilities.

Revaluation of Liabilities. The revaluation of liabilities represents the valuation adjustment of contingent consideration liabilities related to royalty agreements acquired as part of certain business combinations during the year ended March 31, 2015.

Liquids

The following table summarizes the operating results of our liquids segment for the periods indicated:

	Year Ended March 31,		
	2015	2014	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues (1)	$1,265,262	$1,632,948	$(367,686)
Cost of sales	1,217,993	1,559,266	(341,273)
Product margin	47,269	73,682	(26,413)
Other product sales:			
Revenues (1)	1,111,834	1,231,965	(120,131)
Cost of sales	1,038,324	1,179,944	(141,620)
Product margin	73,510	52,021	21,489
Other revenues:			
Revenues (1)	28,745	31,062	(2,317)
Cost of sales	17,313	24,439	(7,126)
Product margin	11,432	6,623	4,809
Expenses:			
Operating expenses	35,580	37,672	(2,092)
General and administrative expenses	8,271	6,443	1,828
Depreciation and amortization expense	13,513	11,018	2,495
Loss on disposal or impairment of assets, net	29,775	5,305	24,470
Total expenses	87,139	60,438	26,701
Segment operating income	$45,072	$71,888	$(26,816)
Propane sold (gallon)	1,285,707	1,190,106	95,601
Propane sold ($/gallon)	$0.984	$1.372	$(0.388)

Cost per propane sold ($/gallon)	$0.947	$1.310	$(0.363)
Propane product margin ($/gallon)	$0.037	$0.062	$(0.025)
Other products sold (gallon)	825,514	786,671	38,843
Other products sold ($/gallon)	$1.347	$1.566	$(0.219)
Cost per other products sold ($/gallon)	$1.258	$1.500	$(0.242)
Other products product margin ($/gallon)	$0.089	$0.066	$0.023

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(1) Revenues include $162.0 million and $245.6 million of intersegment sales during the years ended March 31, 2015 and 2014, respectively, that are eliminated in our consolidated statements of operations.

Propane Sales. The increase in the volume sold from the year ended March 31, 2014 to the year ended March 31, 2015 was due primarily to the inclusion of the natural gas liquids operations acquired from Gavilon Energy for a full fiscal year (compared to only four months of the prior fiscal year) and to the expansion of an agreement under which we market the majority of the production from a fractionation facility.

Our cost of wholesale propane sales during the year ended March 31, 2015 was increased by $4.6 million of net unrealized losses on derivatives. Our cost of wholesale propane sales during the year ended March 31, 2014 was increased by $1.6 million of net unrealized losses on derivatives.

Product margins per gallon of propane sold were lower during the year ended March 31, 2015 than during the prior year. Although we sold a higher volume of propane during the year ended March 31, 2015 than during the prior year, product margins were narrower. During the winter season of the year ended March 31, 2014, the price of propane increased as a result of high demand due to cold weather conditions. During the winter season of the year ended March 31, 2015, propane prices decreased, due primarily to a decline in the price of crude oil. Our product margins are typically higher during periods of rising prices, due to the delay between when we purchase product and when we sell it. We utilize forward contracts and financial derivatives to hedge a portion, but not all, of the price risk associated with holding inventory. In addition, cost of sales during the year ended March 31, 2015 were increased by $4.6 million of net unrealized losses on derivatives, compared to $1.6 million of net unrealized losses on derivatives during the year ended March 31, 2014.

Other Products Sales. Our cost of sales of other products during the year ended March 31, 2015 was reduced by $1.7 million of net unrealized gains on derivatives. Our cost of sales of other products during the year ended March 31, 2014 was reduced by $5.8 million of net unrealized gains on derivatives.

Operating Expenses. This decrease was due primarily to lower compensation expense, $5.0 million of which resulted from a shift in the recording of incentive compensation expense related to bonuses from the liquids segment to “corporate and other” during the year ended March 31, 2015. See further discussion within the “Corporate and Other” section below.

General and Administrative Expenses. This increase was due primarily to expanded operations.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2015, we recorded a loss on disposal of assets of $29.9 million related to the sale of a natural gas liquids terminal. During the year ended March 31, 2014, we recorded an impairment of $5.3 million to the value of the property, plant and equipment of another natural gas liquids terminal.

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Retail Propane

The following table summarizes the operating results of our retail propane segment for the periods indicated:

	Year Ended March 31,		
	2015	2014	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues	$347,575	$388,225	$(40,650)
Cost of sales	181,655	233,110	(51,455)
Product margin	165,920	155,115	10,805
Distillate sales:			
Revenues	106,037	127,672	(21,635)
Cost of sales	85,329	109,058	(23,729)
Product margin	20,708	18,614	2,094
Other product sales:			
Revenues	35,585	35,918	(333)
Cost of sales	11,554	11,531	23
Product margin	24,031	24,387	(356)
Expenses:			
Operating expenses	102,123	96,936	5,187
General and administrative expenses	12,352	11,017	1,335
Depreciation and amortization expense	31,827	28,878	2,949
Loss on disposal or impairment of assets, net	282	—	282
Total expenses	146,584	136,831	9,753
Segment operating income	$64,075	$61,285	$2,790
Propane sold (gallons)	169,279	162,361	6,918
Propane sold ($/gallon)	$2.053	$2.391	$(0.338)
Cost per propane sold ($/gallon)	$1.073	$1.436	$(0.363)
Propane product margin ($/gallon)	$0.980	$0.955	$0.025
Distillates sold (gallons)	34,862	34,965	(103)
Distillates sold ($/gallon)	$3.042	$3.651	$(0.609)
Cost per distillates sold ($/gallon)	$2.448	$3.119	$(0.671)
Distillates product margin ($/gallon)	$0.594	$0.532	$0.062

Revenues. Our retail propane revenues decreased due to the lower demand as the weather conditions were warmer in some markets in the winter of the year ended March 31, 2015 compared to the winter of the prior year. This was partially offset by an increase in volume sold due in part of the growth of our business through acquisitions.

Cost of Sales. Our retail propane segment cost of sales decreased due to the decline in commodity prices.

Operating Expenses. The increase was due primarily to increased compensation expense resulting from the growth of the business.

General and Administrative Expenses. Our retail propane segment incurred $12.4 million of general and administrative expenses during the year ended March 31, 2015, compared to $11.0 million of general and administrative expenses during the year ended March 31, 2014.

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Refined Products and Renewables

The following table summarizes the operating results of our refined products and renewables segment for the periods indicated. Our refined products and renewables segment began with our December 2013 acquisition of Gavilon Energy and significantly expanded with our July 2014 acquisition of TransMontaigne.

	Year Ended March 31,		
	2015	2014	Change
	(in thousands, except per barrel and gallon amounts)		
Refined products sales:			
Revenues (1)	$6,682,040	$1,180,895	$5,501,145
Cost of sales	6,574,545	1,172,754	5,401,791
Product margin	107,495	8,141	99,354
Renewables sales:			
Revenues	473,885	176,781	297,104
Cost of sales	461,996	171,422	290,574
Product margin	11,889	5,359	6,530
Service fee revenues	76,847	—	76,847
Expenses:			
Operating expenses	82,583	6,205	76,378
General and administrative expenses	26,133	156	25,977
Depreciation and amortization expense	32,948	625	32,323
Total expenses	141,664	6,986	134,678
Segment operating income	$54,567	$6,514	$48,053
Refined products sold (barrels)	68,043	9,833	58,210
Refined products sold ($/barrel)	$98.203	$120.095	$(21.892)
Cost per refined products sold ($/barrel)	$96.623	$119.267	$(22.644)
Refined products product margin ($/barrel)	$1.580	$0.828	$0.752
Refined products product margin ($/gallon)	$0.038	$0.020	$0.018
Renewable products sold (barrels)	5,318	3,593	1,725
Renewable products sold ($/barrel)	$89.110	$49.202	$39.908
Cost per renewable products sold ($/barrel)	$86.874	$47.710	$39.164
Renewable products product margin ($/barrel)	$2.236	$1.492	$0.744
Renewable products product margin ($/gallon)	$0.053	$0.036	$0.017

(1) Revenues include $1.1 million of intersegment sales during the year ended March 31, 2015 that are eliminated in our consolidated statement of operations.

Refined Products Revenues. Of the refined products revenues during the year ended March 31, 2015, $3.7 billion was attributable to TransMontaigne.

Refined Products Cost of Sales. Of the refined products cost of sales during the year ended March 31, 2015, $3.6 billion was attributable to TransMontaigne.

Renewables Sales. During December 2014, a federal law was passed that enabled us to claim certain biodiesel tax credits for transactions during calendar year 2014. During the year ended March 31, 2015, our cost of sales was reduced by $5.8 million related to these tax credits.

Service Fee Revenues. Of the service fee revenues during the year ended March 31, 2015, $76.8 million was attributable to TLP.

Operating Expenses. Of the operating expenses during the year ended March 31, 2015, $77.1 million was attributable to TransMontaigne (including TLP).

General and Administrative Expenses. General and administrative expenses during the year ended March 31, 2015 were increased by $8.0 million of compensation expense related to termination benefits for certain TransMontaigne employees. Of the general and administrative expenses during the year ended March 31, 2015, $19.2 million was attributable to TransMontaigne (including TLP).

Depreciation and Amortization Expense. The increase was due primarily to depreciation on TLP's terminal assets and amortization of customer relationship intangible assets acquired in the business combination with TransMontaigne. Of the depreciation and amortization expense during the year ended March 31, 2015, $30.3 million was attributable to TransMontaigne (including TLP).

Corporate and Other

The operating loss within "corporate and other" includes the following components for the periods indicated:

	Year Ended March 31,		
	2015	2014	Change
	(in thousands)		
Compressor leasing business (1)	$133	$2,336	$(2,203)
Natural gas business (2)	(262)	1,363	(1,625)
Equity-based compensation expense	(32,767)	(17,804)	(14,963)
Acquisition expense	(7,382)	(6,908)	(474)
Other corporate expenses	(45,524)	(23,104)	(22,420)
Total	$(85,802)	$(44,117)	$(41,685)

(1) Operating income of our compressor leasing business during the year ended March 31, 2014 includes a $4.4 million gain from the sale of the business in February 2014.

(2) We acquired the natural gas business in our December 2013 acquisition of Gavilon Energy. We subsequently wound down the natural gas business and, as of March 31, 2014, this business has no revenue-generating activity.

The increase in equity-based compensation expense during the year ended March 31, 2015 was due primarily to $10.6 million of expense associated with restricted units granted in July 2014 to certain employees as a bonus that vested in September 2014, $5.0 million of compensation expense otherwise payable in cash to employees of our liquids segment that was instead paid in common units, and an increase in the number of unvested restricted units outstanding resulting from the growth of the business. The impact of these factors was partially offset by the fact that the market value of our common units was lower at March 31, 2015 than at March 31, 2014.

The expenses shown in the table above for acquisitions relate primarily to legal and advisory costs. Acquisition expenses during the year ended March 31, 2015 related primarily to the acquisitions of TransMontaigne and Sawtooth. Acquisition expenses during the year ended March 31, 2014 related primarily to the acquisition of Gavilon Energy.

The increase in other corporate expenses during the year ended March 31, 2015 was due primarily to an increase in compensation expense, due to the addition of new corporate employees to provide general and administrative services in support of the growth of our business. In addition, during January 2015, we reached an agreement with certain employees whereby certain bonus commitments otherwise payable in cash subsequent to our fiscal year end would instead be paid using our common units. Other corporate expenses during the year ended March 31, 2015 include $10.0 million of this bonus expense, which, if paid in cash, would have been reflected in expenses of the crude oil logistics, liquids, and refined products and renewables segments.

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Operating loss during the years ended March 31, 2015 and 2014 was increased by $0.4 million and $2.0 million, respectively, of compensation expense related to bonuses that the previous owners of Gavilon Energy granted to employees, contingent upon successful completion of the sale of the business. These bonuses were paid in December 2014. This amount is reported within “other corporate expenses” in the table above.

Equity in Earnings of Unconsolidated Entities

Equity in earnings of unconsolidated entities was $12.1 million and $1.9 million during the years ended March 31, 2015 and 2014, respectively. The increase was due primarily to an increase of $5.5 million of earnings from BOSTCO and Frontera that we acquired as part of our July 2014 acquisition of TransMontaigne, and an increase of $4.7 million of earnings from Glass Mountain and an ethanol production facility that we acquired as part of our December 2013 acquisition of Gavilon Energy.

Interest Expense

Interest expense was $110.1 million and $58.9 million during the years ended March 31, 2015 and 2014, respectively. The increase in interest expense was due primarily to (i) the increased level of debt outstanding on our Revolving Credit Facility (the average balance outstanding on our Revolving Credit Facility was $1.2 billion during the year ended March 31, 2015, compared to $0.6 billion during year ended March 31, 2014), primarily to finance acquisitions and capital expenditures; (ii) the issuance of $450.0 million of fixed-rate notes during October 2013, which bear a higher interest rate than our Revolving Credit Facility; and (iii) increased interest expense related to TLP’s credit facility (our interest in TLP was acquired in July 2014).

Other Income, Net

The following table summarizes the components of other income, net for the periods indicated:

	Year Ended March 31,	
	2015	2014
	(in thousands)	
Interest income (1)	$ 4,575	$ 1,365
Crude oil marketing arrangement (2)	(5,642)	(1,064)
Crude oil rail transloading facility (3)	31,600	—
Other (4)	6,638	(215)
Other income, net	$ 37,171	$ 86

(1) Relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility to be utilized by a third party and to a loan receivable from an equity method investee.

(2) Represents another party’s share of the profits generated from a joint crude oil marketing arrangement.

(3) In October 2014, we announced plans to build a crude oil rail transloading facility, backed by executed producer commitments. Subsequent to executing these commitments, the producers requested to be released from the commitments. We agreed to release the producers from their commitments in return for a cash payment in March 2015 and additional cash payments over the next five years. In addition, one of the producers committed to pay us a specified fee on each barrel of crude oil it produces in a specified basin over a period of seven years. Upon execution of these agreements in March 2015, we recorded a gain of $31.6 million to other income, net of certain project abandonment costs.

(4) During the year ended March 31, 2015, we settled two separate contractual disputes and recorded $5.5 million of proceeds to other income. Also during the year ended March 31, 2015, we offered to settle another contractual

dispute, and recorded $1.2 million to other expense as an estimate of the probable loss.

Income Tax Expense (Benefit)

Income tax benefit was $3.6 million during the year ended March 31, 2015, compared to $0.9 million of income tax expense during the year ended March 31, 2014. The income tax benefit was due primarily to a benefit of $6.3 million related to the July 2014 acquisition of TransMontaigne, as TransMontaigne was subject to United States federal and state income taxes. On December 30, 2014, we converted TransMontaigne from a taxable entity to a non-taxable entity.

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Noncontrolling Interests

Net income attributable to noncontrolling interests was $12.9 million and $1.1 million during the years ended March 31, 2015 and 2014, respectively. The increase was due primarily to the July 2014 acquisition of TransMontaigne, in which we acquired the 2% general partner interest and a 19.7% limited partner interest in TLP.

Liquidity, Sources of Capital and Capital Resource Activities

Our principal sources of liquidity and capital are the cash flows from our operations and borrowings under our Revolving Credit Facility. See Note 8 to our consolidated financial statements included in this Annual Report for a detailed description of our long-term debt. Our cash flows from operations are discussed below.

Our borrowing needs vary during the year due in part to the seasonal nature of our liquids business. Our greatest working capital borrowing needs generally occur during the period of June through December, when we are building our natural gas liquids inventories in anticipation of the heating season. Our working capital borrowing needs generally decline during the period of January through March, when the cash flows from our retail propane and liquids segments are the greatest.

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash (as defined in our partnership agreement) to unitholders as of the record date. Available cash for any quarter generally consists of all cash on hand at the end of that quarter, less the amount of cash reserves established by our general partner, to (i) provide for the proper conduct of our business, (ii) comply with applicable law, any of our debt instruments or other agreements, and (iii) provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters.

We believe that our anticipated cash flows from operations and the borrowing capacity under our Revolving Credit Facility are sufficient to meet our liquidity needs. If our plans or assumptions change or are inaccurate, or if we make acquisitions, we may need to raise additional capital or sell assets. Our ability to raise additional capital, if necessary, depends on various factors and conditions, including market conditions. We cannot give any assurances that we can raise additional capital to meet these needs (see Part I, Item 1A–"Risk Factors"). Commitments or expenditures, if any, we may make toward any acquisition projects are at our discretion.

We have historically pursued a strategy of growth through acquisitions. Under current market conditions, the cost of capital is much higher than it has been in recent years; prospective lenders seek much higher interest rates than they have sought in the past, and at our prior distribution level of $0.64 per common unit, the yield on our common units was much higher than it had been in the past. In April 2016, the board of directors of our general partner decided to reduce our distribution level from $0.64 per common unit to $0.39 per common unit, which it anticipates will continue for three additional quarters under current market conditions. We expect the reduction in the distribution to provide us with approximately $170 million of annual cash savings to enhance liquidity, repay indebtedness and/or invest in selected growth projects.

Under current market conditions, we are much less likely to pursue acquisitions than we have been in the past. We continue to undertake certain capital expansion projects, including the funding of our portion of the construction of the Joint Pipeline, our assets that will be connected to the Joint Pipeline and the continued development of Sawtooth natural gas liquids storage caverns, among others. We expect to be able to finance these projects through available capacity on our Revolving Credit Facility, asset sales or other forms of financing.

Other sources of liquidity during the three months ended March 31, 2016 and the month of April 2016 are discussed below.

Sale of General Partner Interest in TLP

On February 1, 2016, we completed the sale of our general partner interest in TLP to an affiliate of ArcLight for $350 million in cash.

Sale of TLP Common Units

On April 1, 2016, we sold all of the TLP common units we owned to ArcLight for approximately $112.4 million in cash.

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Class A Convertible Preferred Units

On April 21, 2016, we entered into an agreement to issue $200 million of Preferred Units to Oaktree. Oaktree may acquire 16.6 million Preferred Units at a price of $12.03 per unit as well as 3.6 million warrants, which are subject to certain vesting and exercise terms. We expect to use the net proceeds from the issuance of the Preferred Units to repay borrowings outstanding on our Revolving Credit Facility (as hereinafter defined), which may be re-borrowed in the future to fund capital expenditures and for other general partnership purposes. The first closing of this transaction occurred on May 11, 2016 and we received gross proceeds of $100 million. We expect the second closing to occur prior to June 30, 2016.

Long-Term Debt

Credit Agreement

We have entered into a credit agreement (as amended, the “Credit Agreement”) with a syndicate of banks. The Credit Agreement includes a revolving credit facility to fund working capital needs (the “Working Capital Facility”) and a revolving credit facility to fund acquisitions and expansion projects (the “Expansion Capital Facility,” and together with the Working Capital Facility, the “Revolving Credit Facility”). At March 31, 2016, our Revolving Credit Facility had a total capacity of $2.484 billion. Our Revolving Credit Facility has an “accordion” feature that allows us to increase the capacity by $150 million if new lenders wish to join the syndicate or if current lenders wish to increase their commitments.

The Expansion Capital Facility had a total capacity of $1.446 billion for cash borrowings at March 31, 2016. At that date, we had outstanding borrowings of $1.230 billion on the Expansion Capital Facility. The Working Capital Facility had a total capacity of $1.038 billion for cash borrowings and letters of credit at March 31, 2016. At that date, we had outstanding borrowings of $618.5 million and outstanding letters of credit of $45.4 million on the Working Capital Facility. Amounts outstanding for letters of credit are not recorded as long-term debt on our consolidated balance sheets, although they decrease our borrowing capacity under the Working Capital Facility. The capacity available under the Working Capital Facility may be limited by a “borrowing base” (as defined in the Credit Agreement), which is calculated based on the value of certain working capital items at any point in time.

The commitments under the Credit Agreement expire on November 5, 2018. We have the right to prepay outstanding borrowings under the Credit Agreement without incurring any penalties, and prepayments of principal may be required if we enter into certain transactions to sell assets or obtain new borrowings.

The Credit Agreement is secured by substantially all of our assets. In December 2015, we entered into an agreement with the banks to increase our maximum leverage ratio to 4.75 to 1 at any quarter end. At March 31, 2016, our leverage ratio was approximately 3.9 to 1. The Credit Agreement also specifies that our interest coverage ratio (as defined in the Credit Agreement) cannot be less than 2.75 to 1 at any quarter end. At March 31, 2016, our interest coverage ratio was approximately 5.3 to 1.

At March 31, 2016, we were in compliance with the covenants under the Credit Agreement.

2019 Notes

On July 9, 2014, we issued $400.0 million of 5.125% Senior Notes Due 2019 (the “2019 Notes”) in a private placement exempt from registration under the Securities Act of 1933, as amended (the “Securities Act”), pursuant to Rule 144A and Regulation S under the Securities Act. During the fourth quarter of fiscal year 2016, we repurchased $11.5 million of our 2019 Notes for an aggregate purchase price of $7.0 million (excluding payments of accrued interest). As a result, we recorded a gain on the early extinguishment of our 2019 Notes of $4.5 million (net of the write off of debt issuance costs of $0.1 million)

The 2019 Notes mature on July 15, 2019. Interest is payable on January 15 and July 15 of each year. We have the right to redeem the 2019 Notes before the maturity date, although we would be required to pay a premium for early redemption.

At March 31, 2016, we were in compliance with the covenants under the indenture governing the 2019 Notes.

2021 Notes

On October 16, 2013, we issued $450.0 million of 6.875% Senior Notes Due 2021 (the “2021 Notes”) in a private placement exempt from registration under the Securities Act pursuant to Rule 144A and Regulation S under the Securities Act. During the fourth quarter of fiscal year 2016, we repurchased $61.7 million of our 2021 Notes for an aggregate purchase price

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of $36.4 million (excluding payments of accrued interest). As a result, we recorded a gain on the early extinguishment of our 2021 Notes of $24.0 million (net of the write off of debt issuance costs of $1.2 million)

The 2021 Notes mature on October 15, 2021. Interest is payable on April 15 and October 15 of each year. We have the right to redeem the 2021 Notes before the maturity date, although we would be required to pay a premium for early redemption.

At March 31, 2016, we were in compliance with the covenants under the indenture governing the 2021 Notes.

2022 Notes

On June 19, 2012, we entered into a Note Purchase Agreement (as amended, the "Note Purchase Agreement") whereby we issued $250.0 million of Senior Notes in a private placement (the "2022 Notes"). The 2022 Notes bear interest at a fixed rate of 6.65%, which is payable quarterly. In December 2015, we amended the Note Purchase Agreement to change the covenants to mirror the changes made to the covenants in our Credit Agreement. In addition, we agreed to pay an additional 0.5% per year in interest if our leverage ratio exceeds 4.50 to 1. The 2022 Notes are required to be repaid in semi-annual installments of $25.0 million beginning on December 19, 2017 and ending on the maturity date of June 19, 2022. We have the option to prepay outstanding principal, although we would incur a prepayment penalty. The 2022 Notes are secured by substantially all of our assets and rank equal in priority with borrowings under the Credit Agreement.

At March 31, 2016, we were in compliance with the covenants under the Note Purchase Agreement.

For a further discussion of our Revolving Credit Facility and Senior Notes, see Note 8 to our consolidated financial statements included in this Annual Report.

Revolving Credit Balances

The following table summarizes our Revolving Credit Facility borrowings:

	Average Balance Outstanding	Lowest Balance	Highest Balance
	(in thousands)		
Year Ended March 31, 2016:			
Expansion capital borrowings	$1,067,549	$739,500	$1,380,000
Working capital borrowings	640,928	469,000	756,000
Year Ended March 31, 2015:			
Expansion capital borrowings	$435,752	$114,000	$830,000
Working capital borrowings	736,677	339,500	1,046,000
TLP credit facility borrowings (from July 1, 2014 through March 31, 2015)	250,346	228,000	259,700

Capital Expenditures

The following table summarizes expansion and maintenance capital expenditures for the periods indicated. This information has been prepared on the accrual basis, and excludes property, plant and equipment acquired in acquisitions.

Year Ended March 31,	Capital Expenditures Expansion (1)	Maintenance (2)	Total

	(in thousands)		
2016	$613,598	42,001	$655,599
2015	169,207	40,746	209,953
2014	132,948	32,200	165,148

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(1) Includes expansion capital expenditures for TLP of $13.6 million and $3.7 million during the years ended March 31, 2016 and 2015, respectively.
(2) Includes maintenance capital expenditures for TLP of $11.6 million and $9.8 million during the years ended March 31, 2016 and 2015, respectively.

We currently expect our growth capital expenditures for fiscal year 2017 to be between $200 million and $300 million.

Acquisitions

Subsequent to our IPO, we significantly expanded our operations through numerous acquisitions, as described under Part I, Item 1–"Business–Acquisitions."

Cash Flows

The following table summarizes the sources (uses) of our cash flows for the periods indicated:

	Year Ended March 31,		
Cash Flows Provided by (Used in):	2016	2015	2014
	(in thousands)		
Operating activities, before changes in operating assets and liabilities	$226,881	$107,599	$243,576
Changes in operating assets and liabilities	124,614	154,792	(158,340)
Operating activities	$351,495	$262,391	$85,236
Investing activities	(445,327)	(1,366,221)	(1,455,373)
Financing activities	80,705	1,134,693	1,369,016

Operating Activities. The seasonality of our natural gas liquids businesses has a significant effect on our cash flows from operating activities. Increases in natural gas liquids prices typically reduce our operating cash flows due to higher cash requirements to fund increases in inventories, and decreases in natural gas liquids prices typically increase our operating cash flows due to lower cash requirements to fund increases in inventories.

In general, our operating cash flows are at their lowest levels during our first and second fiscal quarters, or the six months ending September 30, when we experience operating losses or lower operating income as a result of lower volumes of natural gas liquids sales and when we are building our inventory levels for the upcoming heating season. Our operating cash flows are generally greatest during our third and fourth fiscal quarters, or the six months ending March 31, when our operating income levels are highest and customers pay for natural gas liquids consumed during the heating season months. We borrow under our Revolving Credit Facility to supplement our operating cash flows as necessary during our first and second fiscal quarters.

Investing Activities. Net cash used in investing activities was $445.3 million and $1.4 billion during the years ended March 31, 2016 and 2015, respectively. The decrease in net cash used in investing activities was due primarily to:

- a $726.3 million decrease in cash paid for acquisitions during the year ended March 31, 2016 as cash paid for acquisitions during the year ended March 31, 2015 included $580.7 million for the acquisition of TransMontaigne;
- a $343.1 million increase due to proceeds received from the sale of the general partner interest in TLP during the year ended March 31, 2016;
- a $310.0 million decrease for the purchase of the remaining equity interest in Grand Mesa during the year ended March 31, 2015;
-

- a $59.6 million decrease related to a loan receivable associated with our financing of the construction of a natural gas liquids facility to be utilized by a third party; and
- a $24.2 million decrease for the purchase of certain refined product pipeline capacity allocations from other shippers during the year ended March 31, 2015.

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These decreases in net cash used in investing activities were partially offset by:

- an increase in capital expenditures from $203.8 million during the year ended March 31, 2015, $163.0 million of which was expansion capital (of this expansion capital, $3.7 million related to TLP) and $40.8 million of which was maintenance capital (of this maintenance capital, $9.8 million related to TLP), to $536.9 million during the year ended March 31, 2016, $494.9 million of which was expansion capital (of this expansion capital, $13.6 million related to TLP) and $42.0 million of which was maintenance capital (of this maintenance capital, $11.6 million related to TLP);
- a $125.0 million increase due to the purchase of a 37.5% undivided interest in a crude oil pipeline from Colorado to Oklahoma (see "Recent Developments" above) during the year ended March 31, 2016; and
- a $93.5 million decrease in cash flows from derivatives.

Net cash used in investing activities was $1.4 billion and $1.5 billion during the years ended March 31, 2015 and 2014, respectively. The decrease in net cash used in investing activities was due primarily to:

- a $307.9 million decrease in cash paid for acquisitions during the year ended March 31, 2015; and
- a $235.1 million increase in cash flows from derivatives.

These decreases in net cash used in investing activities were partially offset by:

- a $310.0 million increase for the purchase of the remaining equity interest in Grand Mesa during the year ended March 31, 2015;
- a $61.9 million increase related to a loan receivable associated with our financing of the construction of a natural gas liquids facility to be utilized by a third party;
- an increase in capital expenditures from $165.1 million during the year ended March 31, 2014, $132.9 million of which was expansion capital and $32.2 million of which was maintenance capital, to $203.8 million during the year ended March 31, 2015, $163.0 million of which was expansion capital (of this expansion capital, $3.7 million related to TLP) and $40.8 million of which was maintenance capital (of this maintenance capital, $9.8 million related to TLP);
- a $24.2 million increase for the purchase of certain refined product pipeline capacity allocations from other shippers during the year ended March 31, 2015; and
- a $22.0 million increase in contributions to unconsolidated entities during the year ended March 31, 2015 due primarily to our investment in BOSTCO which we acquired as part of our July 2014 acquisition of TransMontaigne.

Financing Activities. Net cash provided by financing activities was $80.7 million and $1.1 billion during the years ended March 31, 2016 and 2015, respectively. The decrease in net cash provided by financing activities was due primarily to:

- $541.1 million in proceeds received from the sale of our common units during the year ended March 31, 2015;
- $400.0 million in proceeds received from the issuance of the 2019 Notes during the year ended March 31, 2015;
- an $88.0 million increase in distributions paid to our partners and noncontrolling interest owners during the year ended March 31, 2016; and
- $43.4 million in repurchases of a portion of our senior notes during the fourth quarter of fiscal year 2016.

These decreases in net cash provided by financing activities were partially offset by an increase of $53.2 million in proceeds from other long-term debt due primarily to equipment financing.

Net cash provided by financing activities was $1.1 billion and $1.4 billion during the years ended March 31, 2015 and 2014, respectively. The decrease in net cash provided by financing activities was due primarily to:

- a $123.8 million increase in distributions paid to our partners and noncontrolling interest owners during the year ended March 31, 2015;

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- a $109.0 million decrease in the proceeds received from the sale of our common units during the year ended March 31, 2015 as more of our common units were issued during the year ended March 31, 2014 to fund acquisitions; and
- a $50.0 million decrease in the proceeds received from debt issuances during the years ended March 31, 2015 and 2014.

These decreases in net cash provided by financing activities were partially offset by a $40.0 million increase in borrowings on our revolving credit facilities (net of repayments) to fund our operating or investing requirements during the year ended March 31, 2015. To the extent our cash flows from operating activities are not sufficient to finance our required distributions to our partners and noncontrolling interest owners, we may be required to increase borrowings under our Working Capital Facility.

The following table summarizes distributions declared during the years ended March 31, 2016, 2015 and 2014:

Date Declared	Record Date	Date Paid	Amount Per Unit	Amount Paid To Limited Partners (in thousands)	Amount Paid To General Partner (in thousands)
April 25, 2013	May 6, 2013	May 15, 2013	$0.4775	$ 25,605	$ 1,189
July 25, 2013	August 5, 2013	August 14, 2013	0.4938	31,725	1,739
October 23, 2013	November 4, 2013	November 14, 2013	0.5113	35,908	2,491
January 24, 2014	February 4, 2014	February 14, 2014	0.5313	42,150	4,283
April 24, 2014	May 5, 2014	May 15, 2014	0.5513	43,737	5,754
July 24, 2014	August 4, 2014	August 14, 2014	0.5888	52,036	9,481
October 24, 2014	November 4, 2014	November 14, 2014	0.6088	53,902	11,141
January 26, 2015	February 6, 2015	February 13, 2015	0.6175	54,684	11,860
April 24, 2015	May 5, 2015	May 15, 2015	0.6250	59,651	13,446
July 23, 2015	August 3, 2015	August 14, 2015	0.6325	66,248	15,483
October 22, 2015	November 3, 2015	November 13, 2015	0.6400	67,313	16,277
January 21, 2016	February 3, 2016	February 15, 2016	0.6400	67,310	16,279
April 21, 2016	May 3, 2016	May 13, 2016	0.3900	40,626	70

The following table summarizes distributions declared by TLP after our acquisition of general and limited partner interests in TLP (exclusive of the distribution declared in July 2014, the proceeds of which we remitted to the former owners of TransMontaigne, pursuant to agreements entered into at the time of the business combination. On February 1, 2016, we sold our general partner interest in TLP. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting.

Date Declared	Record Date	Date Paid	Amount Per Unit	Amount Paid To NGL (in thousands)	Amount Paid To Noncontrolling Interest Owners (in thousands)
October 13, 2014	October 31, 2014	November 7, 2014	$0.6650	$ 4,010	$ 8,614
January 8, 2015	January 30, 2015	February 6, 2015	0.6650	4,010	8,614
April 13, 2015	April 30, 2015	May 7, 2015	0.6650	4,007	8,617
July 13, 2015	July 31, 2015	August 7, 2015	0.6650	4,007	8,617
October 12, 2015	October 30, 2015	November 6, 2015	0.6650	4,007	8,617
January 19, 2016	January 29, 2016	February 8, 2016	0.6700	4,104	8,681

Common Unit Repurchase Program

On September 10, 2015, the Board of Directors of our general partner authorized a common unit repurchase program pursuant to which we could repurchase up to $45 million of our outstanding common units through March 31, 2016 from time to time in the open market or in other privately negotiated transactions. During the year ended March 31, 2016, we repurchased 1,623,804 common units for an aggregate price of $17.7 million.

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Contractual Obligations

The following table summarizes our contractual obligations at March 31, 2016 for our fiscal years ending thereafter:

		Years Ending March 31,					
	Total	2017	2018	2019	2020	2021	Thereafter
	(in thousands)						
Principal payments on long-term debt —							
Expansion capital borrowings	$1,229,500	$—	$—	$1,229,500	$—	$—	$—
Working capital borrowings	618,500	—	—	618,500	—	—	—
2019 Notes	388,467	—	—	—	388,467	—	—
2021 Notes	388,289	—	—	—	—	—	388,289
2022 Notes	250,000	—	25,000	50,000	50,000	50,000	75,000
Other long-term debt	61,488	7,899	7,143	6,053	5,621	34,671	101
Interest payments on long-term debt —							
Revolving Credit Facility (1)	149,937	57,668	57,668	34,601	—	—	—
2019 Notes	70,639	20,226	20,165	20,165	10,083	—	—
2021 Notes	160,731	27,256	26,695	26,695	26,695	26,695	26,695
2022 Notes	66,500	16,625	16,209	13,300	9,975	6,650	3,741
Other long-term debt	14,257	3,739	3,323	2,908	2,521	1,762	4
Letters of credit	45,418	—	—	45,418	—	—	—
Future minimum lease payments under noncancelable operating leases	647,759	136,065	120,723	98,266	87,569	77,821	127,315
Future minimum throughput payments under noncancelable agreements (2)	200,734	53,024	53,042	52,250	42,418	—	—
Construction commitments (3)	126,800	126,800	—	—	—	—	—
Fixed-price commodity purchase commitments (4)	50,249	50,047	202	—	—	—	—
Index-price commodity purchase commitments (5)	883,908	685,092	92,891	73,928	31,997	—	—
Total contractual obligations	$5,353,176	$1,184,441	$423,061	$2,271,584	$655,346	$197,599	$621,145

(1) The estimated interest payments on our Revolving Credit Facility are based on principal and letters of credit outstanding at March 31, 2016. See Note 8 to our consolidated financial statements included in this Annual Report for additional information on our Credit Agreement.

(2) We have executed noncancelable agreements with crude oil and refined products pipeline operators, which guarantee us minimum monthly shipping capacity on the pipelines. As a result, we are required to pay the minimum shipping fees if actual shipments are less than our allotted capacity.

(3) At March 31, 2016, we had the following construction commitments:

- As discussed above, in November 2015, we reached an agreement with Saddlehorn to jointly construct, own and operate the Joint Pipeline. At March 31, 2016, our share of the remaining total construction costs for the Joint Pipeline is approximately $39 million. We expect the Joint Pipeline to be operational beginning in the third quarter of fiscal year 2017.
- As part of the Joint Pipeline project, we will have some assets connected to the Joint Pipeline. At March 31, 2016, the remaining costs for these assets are approximately $80.6 million. We expect these assets to be completed during the third quarter of fiscal year 2017.
- In February 2015, we acquired Sawtooth, which owns a natural gas liquids salt dome storage facility in Utah with rail and truck access to western United States markets and entered into a construction agreement to expand the storage

capacity of the facility. At March 31, 2016, the remaining costs for this project are $7.2 million. We expect this project to be completed by the end of the second quarter of fiscal year 2017.

(4) At March 31, 2016, we had the following fixed-price purchase commitments (in thousands):

	Crude Oil		Natural Gas Liquids	
	Value	Volume (in barrels)	Value	Volume (in gallons)
2017	$41,756	1,077	$8,291	21,574
2018	—	—	202	504
Total	$41,756	1,077	$8,493	22,078

(5) At March 31, 2016, we had the following index-price purchase commitments (in thousands):

	Crude Oil		Natural Gas Liquids	
	Value	Volume (in barrels)	Value	Volume (in gallons)
2017	$319,761	9,187	$365,331	855,645
2018	92,745	2,640	146	300
2019	73,928	1,825	—	—
2020	31,997	1,070	—	—
Total	$518,431	14,722	$365,477	855,945

Index prices are based on a forward price curve at March 31, 2016. A theoretical change of $0.10 per gallon in the underlying commodity price at March 31, 2016 would result in a change of $85.6 million in the value of our index-price natural gas liquids purchase commitments. A theoretical change of $1.00 per barrel in the underlying commodity price at March 31, 2016 would result in a change of $14.7 million in the value of our index-price crude oil purchase commitments.

Sales Contracts

We have entered into product sales contracts for which we expect the parties to physically settle the inventory in future periods. At March 31, 2016, we had the following sales contract volumes (in thousands):

Natural gas liquids fixed-price (gallons)	85,162
Natural gas liquids index-price (gallons)	312,198
Crude oil fixed-price (barrels)	2,107
Crude oil index-price (barrels)	18,754

Off-Balance Sheet Arrangements

We do not have any off balance sheet arrangements other than the operating leases described in Note 10 to our consolidated financial statements included in this Annual Report.

Environmental Legislation

Please see Part I, Item 1–“Business–Government Regulation–Greenhouse Gas Regulation” for a discussion of proposed environmental legislation and regulations that, if enacted, could result in increased compliance and operating costs. However, at this time we cannot predict the structure or outcome of any future legislation or regulations or the eventual cost we could incur in compliance.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that are applicable to us, see Note 2 to our consolidated financial statements included in this Annual Report.

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Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with GAAP requires the selection and application of appropriate accounting principles to the relevant facts and circumstances of the Partnership's operations and the use of estimates made by management. We have identified the following accounting policies that are most important to the portrayal of our consolidated financial position and results of operations. The application of these accounting policies, which requires subjective or complex judgments regarding estimates and projected outcomes of future events, and changes in these accounting policies, could have a material effect on our consolidated financial statements.

Revenue Recognition

We record product sales revenues when title to the product transfers to the purchaser, which typically occurs when the purchaser receives the product. We record terminaling, transportation, storage, and service revenues when the service is performed, and we record tank and other rental revenues over the lease term. Several of our terminaling service agreements with throughput customers, allow us to receive the product volume gained resulting from differences between the measurement of product volumes received and distributed at our terminaling facilities. Such differences are due to the inherent variances in measurement devices and methodology. We record revenues for the net proceeds from the sale of the product gained. Revenues for our water solutions segment are recognized when we obtain the wastewater at our treatment and disposal facilities.

We report taxes collected from customers and remitted to taxing authorities, such as sales and use taxes, on a net basis. We include amounts billed to customers for shipping and handling costs in revenues in our consolidated statements of operations.

We enter into certain contracts whereby we agree to purchase product from a counterparty and sell the same volume of product to the same counterparty at a different location or time. When such agreements are entered into at the same time and in contemplation of each other, we record the revenues for these transactions net of cost of sales.

Derivative Financial Instruments

We record all derivative financial instrument contracts at fair value in our consolidated balance sheets except for certain contracts that qualify for the normal purchase and normal sale election. Under this accounting policy election, we do not record the contracts at fair value at each balance sheet date; instead, we record the purchase or sale at the contracted value once the delivery occurs.

We have not designated any financial instruments as hedges for accounting purposes. All changes in the fair value of our commodity derivative instruments that do not qualify as normal purchases and normal sales (whether cash transactions or non-cash mark-to-market adjustments) are reported within cost of sales in our consolidated statements of operations, regardless of whether the contract is physically or financially settled.

We utilize various commodity derivative financial instrument contracts to attempt to reduce our exposure to price fluctuations. We do not enter into such contracts for trading purposes. Changes in assets and liabilities from commodity derivative financial instruments result primarily from changes in market prices, newly originated transactions, and the timing of settlements. We attempt to balance our contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. However, net unbalanced positions can exist or are established based on our assessment of anticipated market movements. Inherent in the resulting contractual portfolio are certain business risks, including market risk and credit risk. Market risk is the risk that the value of the portfolio will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. Procedures and limits for managing commodity price risks and credit risks are specified in our market risk policy and credit risk policy, respectively. Open commodity positions and market price changes are monitored daily and are reported to senior management and to marketing operations personnel. Credit risk is monitored daily and exposure is minimized through customer deposits, restrictions on product liftings, letters of credit, and entering into master netting agreements that allow for offsetting counterparty receivable and payable balances for certain transactions.

Impairment of Long-Lived Assets

We evaluate the carrying value of our long-lived assets (property, plant and equipment and amortizable intangible assets) for potential impairment when events and circumstances warrant such a review. A long-lived asset group is considered impaired when the anticipated undiscounted future cash flows from the use and eventual disposition of the asset group is less than its carrying value. We compare the carrying value of the long-lived asset to the estimated undiscounted future cash flows expected to be generated from that asset. Estimates of future net cash flows include estimating future volumes, future margins or tariff rates, future operating costs and other estimates and assumptions consistent with our business plans. If we determine that an asset's unamortized cost may not be recoverable due to impairment, we may be required to reduce the carrying value and the subsequent useful life of the asset. Any such write-down of the value and unfavorable change in the useful life of a long-lived assets would increase costs and expenses at that time.

We evaluate equity method investments for impairment when we believe the current fair value may be less than the carrying amount. We record impairments of equity method investments if we believe the decline in value is other than temporary.

Impairment of Goodwill

Goodwill is subject to at least an annual assessment for impairment. We perform our annual assessment of impairment during the fourth quarter of our fiscal year, and more frequently if circumstances warrant. For purposes of goodwill impairment testing, assets are grouped into "reporting units". A reporting unit is either an operating segment or a component of an operating segment, depending on how similar the components of the operating segment are to each other in terms of operational and economic characteristics. For each reporting unit, we perform a qualitative assessment of relevant events and circumstances about the likelihood of goodwill impairment. If it is deemed more likely than not the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not required. The qualitative assessment is based on reviewing the totality of several factors, including macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, other entity specific events (for example, changes in management) or other events such as selling or disposing of a reporting unit. The determination of a reporting unit's fair value is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins, (ii) long-term growth rates for cash flows beyond the discrete forecast period, (iii) appropriate discount rates and (iv) estimates of the cash flow multiples to apply in estimating the market value of our reporting units. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings may be required to reduce the carrying value of goodwill to its implied fair value. If future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations. We monitor the markets for our products and services, in addition to the overall market, to determine if a triggering event occurs that would indicate that the fair value of a reporting unit is less than its carrying value.

Asset Retirement Obligations

We are required to recognize the fair value of a liability for an asset retirement obligation if a reasonable estimate of fair value can be made. In order to determine the fair value of such a liability, we must make certain estimates and assumptions including, among other things, projected cash flows, the estimated timing of retirement, a credit-adjusted risk-free interest rate, and an assessment of market conditions, which could significantly impact the estimated fair value of the asset retirement obligation. These estimates and assumptions are very subjective and can vary over time. Our consolidated balance sheet at March 31, 2016 includes a liability of $5.6 million related to asset retirement obligations, which is reported within other noncurrent liabilities. We have contractual and regulatory obligations at certain facilities for which we have to perform remediation, dismantlement, or removal activities when the assets are retired. Our liability for asset retirement obligations is discounted to present value. To calculate the liability, we make estimates and assumptions about the retirement cost and the timing of retirement. Changes in our assumptions and estimates may occur as a result of the passage of time and the occurrence of future events.

In addition to the obligations described above, we may be obligated to remove facilities or perform other remediation upon retirement of certain other assets. We do not believe the present value of these asset retirement obligations, under current laws and regulations, after taking into consideration the estimated lives of our facilities, is material to our consolidated financial position or results of operations.

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

Depreciation expense is the systematic write-off of the cost of our property, plant and equipment, net of residual or salvage value (if any), to the results of operations for the quarterly and annual periods during which the assets are used. We depreciate the majority of our property, plant and equipment using the straight-line method, which results in our recording depreciation expense evenly over the estimated life of the individual asset. The estimate of depreciation expense requires us to make assumptions regarding the useful economic lives and residual values of our assets. When we acquire and place our property, plant and equipment in service, we develop assumptions about the useful economic lives and residual values of such assets that we believe to be reasonable; however, circumstances may develop that could require us to change these assumptions in future periods, which would change our depreciation expense prospectively. Examples of such circumstances include changes in laws and regulations that limit the estimated economic life of an asset, changes in technology that render an asset obsolete, or changes in expected salvage values.

Amortization of Intangible Assets

Amortization expense is the systematic write-off of the cost of our amortizable intangible assets to the results of operations for the quarterly and annual periods during which the assets are used. We amortize the majority of these intangible assets using the straight-line method, which results in our recording amortization expense evenly over the estimated life of the individual asset. The estimate of amortization expense requires us to make assumptions regarding the useful economic lives of our assets. When we acquire intangible assets, we develop assumptions about the useful economic lives of such assets that we believe to be reasonable; however, circumstances may develop that could require us to change these assumptions in future periods, which would change our amortization expense prospectively. Examples of such circumstances include changes in customer attrition rates and changes in laws and regulations that could limit the estimated economic life of an asset.

Tank Bottoms

Tank bottoms, which are product volumes required for the operation of storage tanks, are recorded at historical cost within either noncurrent assets or property, plant and equipment on our consolidated balance sheets. We recover tank bottoms when the storage tanks are removed from service. See Note 2 and Note 5 to our consolidated financial statements included in this Annual Report.

Linefill

We have entered into long-term shipment commitments for specified minimum volumes of crude oil on certain third-party owned pipelines. These agreements require that we maintain a certain minimum amount of crude oil in the pipeline to serve as linefill over the duration of the agreement. We report such linefill at historical cost within other noncurrent assets on our consolidated balance sheets. See Note 2 to our consolidated financial statements included in this Annual Report.

Business Combinations

We record business combinations using the “acquisition method,” in which the assets acquired and liabilities assumed in a business combination at their acquisition date fair values. Fair values of assets acquired and liabilities assumed are based upon available information and may involve engaging an independent third party to perform an appraisal. Estimating fair values can be complex and subject to significant business judgment. We must also identify and include in the allocation all acquired tangible and intangible assets that meet certain criteria, including assets that were not previously recorded by the acquired entity. The estimates most commonly involve property, plant and equipment and intangible assets, including those with indefinite lives. The estimates also include the fair value of contracts including commodity purchase and sale agreements, storage contracts, and transportation contracts. The excess of the purchase price over the net fair value of acquired assets and assumed liabilities is recorded as goodwill, which is not amortized but is reviewed annually for impairment. Pursuant to GAAP, an entity is allowed a reasonable period of time (not to exceed one year) to obtain the information necessary to identify and measure the value of the assets acquired and liabilities assumed in a business combination.

Inventories

Our inventories consist primarily of crude oil, natural gas liquids, refined products, ethanol, and biodiesel. The market values of these commodities change on a daily basis as supply and demand conditions change. We value our inventories at the lower of cost or market, with cost determined using either the weighted-average cost or the first in, first out (FIFO) methods, including the cost of transportation and storage. Market is determined based on estimated replacement cost using prices at the end of the reporting period. At the end of each fiscal year, we also perform a "lower of cost or market" analysis; if the cost basis of the inventories would not be recoverable based on market prices at the end of the year, we reduce the book value of the inventories to the recoverable amount. In performing this analysis, we consider fixed-price forward commitments and the opportunity to transfer propane inventory from our wholesale liquids business to our retail propane business to sell the inventory in retail markets. When performing this analysis during interim periods within a fiscal year, accounting standards do not require us to record a lower of cost or market write-down if we expect the market values to recover by our fiscal year end. We are unable to control changes in the market value of these commodities and are unable to determine whether write-downs will be required in future periods. In addition, write-downs at interim periods could be required if we cannot conclude that market values will recover sufficiently by our fiscal year end.

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Equity-Based Compensation

Our general partner has granted certain restricted units to employees and directors under a long-term incentive plan. The restricted units include awards that vest contingent on the continued service of the recipients through the vesting date (the "Service Awards"). The restricted units also include awards that are contingent both on the continued service of the recipients through the vesting date and also on the performance of our common units relative to other entities in the Alerian MLP Index (the "Index") over specified periods of time (the "Performance Awards"). The awards may also vest in the event of a change in control, at the discretion of the board of directors.

We record the expense for the first tranche of each Service Award on a straight-line basis over the period beginning with the grant date of the awards and ending with the vesting date of the tranche. We record the expense for succeeding tranches over the period beginning with the vesting date of the previous tranche and ending with the vesting date of the tranche. At each balance sheet date, we adjust the cumulative expense recorded using the estimated fair value of the awards at the balance sheet date. We calculate the fair value of the awards using the closing price of our common units on the New York Stock Exchange on the balance sheet date, adjusted to reflect the fact that the holders of the unvested units are not entitled to distributions during the vesting period. We estimate the impact of the lack of distribution rights during the vesting period using the value of the most recent distribution and assumptions that a market participant might make about future distributions.

We record the expense for each of the tranches of the Performance Awards on a straight-line basis over the period beginning with the grant date and ending with the vesting date of the tranche. At each balance sheet date, we adjust the cumulative expense recorded using the estimated fair value of the awards at the balance sheet date. We calculate the fair value of the awards using a Monte Carlo simulation.

We report unvested units as liabilities in our consolidated balance sheets. When units vest and are issued, we record an increase to equity.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

A significant portion of our long-term debt is variable-rate debt. Changes in interest rates impact the interest payments of our variable-rate debt but generally do not impact the fair value of the liability. Conversely, changes in interest rates impact the fair value of the fixed-rate debt but do not impact its cash flows.

Our Revolving Credit Facility is variable-rate debt with interest rates that are generally indexed to bank prime or LIBOR interest rates. At March 31, 2016, we had $1.8 billion of outstanding borrowings under our Revolving Credit Facility at a rate of 2.94%. A change in interest rates of 0.125% would result in an increase or decrease of our annual interest expense of $2.3 million, based on borrowings outstanding at March 31, 2016.

Commodity Price and Credit Risk

Our operations are subject to certain business risks, including commodity price risk and credit risk. Commodity price risk is the risk that the market value of crude oil, natural gas liquids, and refined products will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract.

Procedures and limits for managing commodity price risks and credit risks are specified in our market risk policy and credit risk policy, respectively. Open commodity positions and market price changes are monitored daily and are reported to senior management and to marketing operations personnel. Credit risk is monitored daily and exposure is minimized through customer deposits, restrictions on product liftings, letters of credit and entering into master netting agreements that allow for offsetting counterparty receivable and payable balances for certain transactions, as deemed appropriate. At March 31, 2016, our primary counterparties were retailers, resellers, energy marketers, producers, refiners, and dealers.

The crude oil, natural gas liquids, and refined products industries are “margin-based” and “cost-plus” businesses in which gross profits depend on the differential of sales prices over supply costs. We have no control over market conditions. As a result, our profitability may be impacted by sudden and significant changes in the price of crude oil, natural gas liquids, and refined products.

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We engage in various types of forward contracts and financial derivative transactions to reduce the effect of price volatility on our product costs, to protect the value of our inventory positions, and to help ensure the availability of product during periods of short supply. We attempt to balance our contractual portfolio by purchasing volumes when we have a matching purchase commitment from our wholesale and retail customers. We may experience net unbalanced positions from time to time. In addition to our ongoing policy to maintain a balanced position, for accounting purposes we are required, on an ongoing basis, to track and report the market value of our derivative portfolio.

Although we use financial derivative instruments to reduce the market price risk associated with forecasted transactions, we do not account for financial derivative transactions as hedges. We record the changes in fair value of these financial derivative transactions within cost of sales. The following table summarizes the hypothetical impact on the March 31, 2016 fair value of our commodity derivatives of an increase of 10% in the value of the underlying commodity (in thousands):

	Increase (Decrease) To Fair Value
Crude oil (crude oil logistics segment)	$ (6,163)
Crude oil (water solutions segment)	(2,656)
Propane (liquids segment)	963
Other products (liquids segment)	(296)
Refined products (refined products and renewables segment)	(24,736)
Renewables (refined products and renewables segment)	(4,508)
Canadian dollars (liquids segment)	945

Fair Value

We use observable market values for determining the fair value of our derivative instruments. In cases where actively quoted prices are not available, other external sources are used which incorporate information about commodity prices in actively quoted markets, quoted prices in less active markets and other market fundamental analysis.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements beginning on page F-1 of this Annual Report, together with the report of Grant Thornton LLP, our independent registered public accounting firm, are incorporated by reference into this Item 8.

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

We maintain disclosure controls and procedures, as defined in Rule 13(a)-15(e) and 15(d)-15(e) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), that are designed to provide reasonable assurance that information required to be disclosed in our filings and submissions under the Exchange Act is recorded, processed, summarized and reported within the periods specified in the rules and forms of the Securities and Exchange Commission (“SEC”) and that such information is accumulated and communicated to our management, including the principal executive officer and principal financial officer of our general partner, as appropriate, to allow timely decisions regarding required disclosure.

We completed an evaluation under the supervision and with participation of our management, including the principal executive officer and principal financial officer of our general partner, of the effectiveness of the design and operation of our disclosure controls and procedures as of March 31, 2016. Based on this evaluation, the principal executive officer and principal financial officer of our general partner have concluded that as of March 31, 2016, such disclosure controls and procedures were effective to provide the reasonable assurance described above.

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Management's Report on Internal Control Over Financial Reporting

The management of our Delaware limited partnership (the "Partnership") and subsidiaries is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13(a)-15(f). Under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer of our general partner, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the 2013 Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, or the COSO framework.

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of March 31, 2016.

Our internal control over financial reporting as of March 31, 2016 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report, which appears in Part IV, Item 15 - "Exhibits, Financial Statement Schedules" in this Annual Report.

Changes in Internal Control Over Financial Reporting

The Partnership had a change in key personnel and controls in the fourth quarter of its 2016 fiscal year. More specifically, the Partnership's general partner hired a new Chief Accounting Officer and a new Chief Financial Officer. These personnel additions (1) changed the design of the Chief Accounting Officer's review control over business combination accounting, and (2) added a new and incremental control encompassing the Chief Financial Officer review of business combination accounting for accuracy and the fair value measurements for reasonableness. Both of these internal control modifications began in the fourth quarter of fiscal 2016. Through execution of these controls over the recording of business combinations that occurred in the fourth quarter of fiscal 2016, the Chief Accounting Officer and Chief Financial Officer identified certain contingent consideration liabilities in connection with the fourth quarter 2016 business combinations, and determined that the Partnership had failed to record similar liabilities for contingent consideration related to certain previous business combinations that had occurred prior to the fourth quarter of fiscal year 2016. Such liabilities should have been recorded at the acquisition date and subsequently revalued to estimated fair value at each reporting period with the offset to current earnings. Based on the determination that the Partnership had not properly accounted for these prior acquisitions, management determined that a material weakness in internal control existed through December 31, 2015, specifically related to the identification and review of accounting for assets acquired and liabilities assumed in business combinations. As described above in "Management's Report on Internal Control Over Financial Reporting", the Partnership concluded that its internal control over financial reporting was effective as of March 31, 2016 based, in part, on the effectiveness of the changed and new controls implemented in the fourth quarter of fiscal year 2016.

Other than changes that have been described above, there have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) of the Exchange Act) during the three months ended March 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Board of Directors of our General Partner

NGL Energy Holdings LLC, our general partner, manages our operations and activities on our behalf through its directors and executive officers. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operations. The NGL Energy GP Investor Group appoints all members to the board of directors of our general partner.

The board of directors of our general partner currently has ten members. The board of directors of our general partner has determined that Mr. Kneale, Mr. Cropper, and Mr. Collingsworth satisfy the New York Stock Exchange ("NYSE") and SEC independence requirements. The NYSE does not require a listed publicly traded limited partnership like us to have a majority of independent directors on the board of directors of our general partner. In addition, we are not required to have a nominating and corporate governance committee.

In evaluating director candidates, the NGL Energy GP Investor Group assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the ability of the board of directors of our general partner to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the board to fulfill their duties. Our general partner has no minimum qualifications for director candidates. In general, however, the NGL Energy GP Investor Group reviews and evaluates both incumbent and potential new directors in an effort to achieve diversity of skills and experience among the directors of our general partner and in light of the following criteria:

- experience in business, government, education, technology or public interests;
- high-level managerial experience in large organizations;
- breadth of knowledge regarding our business and industry;
- specific skills, experience or expertise related to an area of importance to us, such as energy production, consumption, distribution or transportation, government, policy, finance or law;
- moral character and integrity;
- commitment to our unitholders' interests;
- ability to provide insights and practical wisdom based on experience and expertise;
- ability to read and understand financial statements; and
- ability to devote the time necessary to carry out the duties of a director, including attendance at meetings and consultation on partnership matters.

Although our general partner does not have a formal policy in regard to the consideration of diversity in identifying director nominees, qualified candidates for nomination to the board are considered without regard to race, color, religion, gender, ancestry or national origin.

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Directors and Executive Officers

Directors of our general partner are appointed by the NGL Energy GP Investor Group and hold office until their successors have been duly elected and qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers are appointed by, and serve at the discretion of, the board of directors of our general partner. The following table summarizes information regarding the current directors of our general partner and our executive officers.

Name	Age	Position with NGL Energy Holdings LLC
H. Michael Krimbill	62	Chief Executive Officer and Director
Robert W. Karlovich III	39	Chief Financial Officer and Treasurer
James J. Burke	60	President and Director
Shawn W. Coady	54	President and Chief Operating Officer, Retail Division and Director
Vincent J. Osterman	59	President, Eastern Retail Propane Operations and Director
Christopher Beall	41	Director
James M. Collingsworth	61	Director
Stephen L. Cropper	66	Director
Bryan K. Guderian	56	Director
James C. Kneale	64	Director
John T. Raymond	45	Director
Patrick Wade	46	Director

H. Michael Krimbill. Mr. Krimbill has served as our Chief Executive Officer since October 2010 and as a member of the board of directors of our general partner since its formation in September 2010. From February 2007 through September 2010, Mr. Krimbill managed private investments. Mr. Krimbill was the President and Chief Financial Officer of Energy Transfer Partners, L.P. from 2004 until his resignation in January 2007. Mr. Krimbill joined Heritage Propane Partners, L.P., the predecessor of Energy Transfer Partners, L.P., as Vice President and Chief Financial Officer in 1990. Mr. Krimbill was President of Heritage Propane Partners, L.P. from 1999 to 2000 and President and Chief Executive Officer of Heritage Propane Partners, L.P. from 2000 to 2005. Mr. Krimbill also served as a director of Energy Transfer Equity, the general partner of Energy Transfer Partners, L.P., from 2000 to January 2007, Williams Partners L.P. from 2007 to September 2012, and Pacific Commerce Bank from January 2011 to March 2015.

Mr. Krimbill brings leadership, oversight and financial experience to the board. Mr. Krimbill provides expertise in managing and operating a publicly traded partnership, including substantial expertise in successfully acquiring and integrating propane and midstream businesses. Mr. Krimbill also brings financial expertise to the board, including his prior service as a chief financial officer. Mr. Krimbill’s experience serving on other public company boards is also a valuable asset to our board of directors.

Robert W. Karlovich III. Mr. Karlovich was appointed as our Chief Financial Officer in February 2016. Prior to joining NGL, Mr. Karlovich served as Chief Financial Officer of Targa Pipeline Partners, a subsidiary of Targa Resources Partners, LP, from February 2015 through February 2016, and as Senior Vice President of Commercial and Business Development for Targa Resources Partners LP from November 2015 to February 2016. Mr. Karlovich served in various roles at Atlas Pipeline Partners, L.P. and its subsidiaries (“APL”) from September 2006 to February 2015 when APL merged with Targa Resources Partners, LP. Mr. Karlovich served in various roles at Syntroleum Corporation from February 2004 to September 2006. Prior to that, Mr. Karlovich worked at Arthur Andersen LLP and Grant Thornton LLP. Mr. Karlovich is a certified public accountant.

James J. Burke. Mr. Burke serves as our President and joined the board of directors of our general partner in 2012. Mr. Burke was a co-founder of High Sierra Energy, LP and High Sierra Energy GP, LLC (“High Sierra”) and served as

Chairman of the High Sierra board and President and Chief Executive Officer of the High Sierra general partner since September 2010 until NGL's acquisition of High Sierra in June 2012. From July 2004 to September 2010, Mr. Burke was the Managing Director of High Sierra's general partner. Mr. Burke, along with three other entrepreneurs, co-founded Petro Source Partners, LP, where he ran six business units throughout the United States and Canada for the company over a 17-year span. Prior to that, Mr. Burke served as Manager of Crude Oil Acquisitions at Asamera Oil (United States) Inc. from 1981 to 1984. Mr. Burke began his career as a Crude Oil Representative at Permian Corporation, where he worked from 1978 to 1981. Mr. Burke also serves as the Managing Director of Impact Energy Services, LLC.

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Mr. Burke brings valuable executive and operational experience in the crude oil marketing business and water solutions business to the board and provides expertise in both acquisitions and organic growth strategies.

Shawn W. Coady. Dr. Coady has served as our President and Chief Operating Officer, Retail Division, since April 2012 and previously served as our Co-President and Chief Operating Officer, Retail Division from October 2010 through April 2012. Dr. Coady has also served as a member of the board of directors of our general partner since its formation in September 2010. Dr. Coady served as an officer of Hicks Oils & Hicksgas, Incorporated ("HOH"), from March 1989 to September 2010 when HOH contributed its propane and propane related assets to Hicksgas LLC, and the membership interests in Hicksgas LLC were contributed to us as part of our formation transactions. Dr. Coady was also the President of Hicksgas Gifford, Inc. from March 1989 until the membership interests in the company were contributed to us as part of our formation transactions. Dr. Coady has served as a director for the National Propane Gas Association since 2004 and as a member of the executive committee of the Illinois Propane Gas Association from 2004 to March 2015.

Dr. Coady brings valuable management and operational experience to the board. Dr. Coady has over 25 years of experience in the retail propane industry, and provides expertise in both acquisition and organic growth strategies. Dr. Coady also provides insight into developments and trends in the propane industry through his leadership roles in industry associations.

Vincent J. Osterman. Mr. Osterman has served as the President of Osterman Associated Companies, which contributed the assets of its propane operations to us on October 3, 2011, since August 1987. Mr. Osterman has served as President of our Eastern Retail Propane Operations and as a member of the board of directors of our general partner since October 2011. Mr. Osterman also currently serves on the board of directors of Energi Holdings, Inc. and on the Board of Advisors of the Gaudette Insurance Agency.

With his long tenure as President of the Osterman Associated Companies, Mr. Osterman brings valuable executive and operational experience in the retail propane businesses to the board. Mr. Osterman also provides insight into developments and trends in the propane industry through his leadership roles in industry associations.

Christopher Beall. Mr. Beall has served on the board of directors of our general partner since May 2016. Mr. Beall is a Managing Director and Co-Portfolio Manager of Oaktree Capital Management L.P.'s ("Oaktree") Infrastructure Investing Strategy. Mr. Beall has over 16 years of experience in direct investments, investment banking and finance. Mr. Beall served as a key investment professional for Highstar Capital for ten years prior to joining Oaktree in 2014 and continues to serve as a Partner of Highstar Capital for certain legal funds not managed by Oaktree. Prior to joining Highstar Capital in 2004, he worked in the Global Natural Resources Group at Lehman Brothers, Inc., and in operations and engineering at Koch Pipeline Company, a natural gas transmission pipeline owned by Koch Industries, Inc. Mr. Beall currently serves on the board of directors of Northstar Transloading, ADS Waste Holding, Inc., Ports America Companies, Wespac Midstream and Amtrak.

Mr. Beall brings considerable experience in the energy business and in financial markets. As a director for other public companies, Mr. Beall also provides cross board experience.

James M. Collingsworth. Mr. Collingsworth has served on the board of directors of our general partner since January 2015. Mr. Collingsworth previously served as a Senior Vice President of the general partner of Enterprise Products Partners L.P. from November 2001 through September 2012. Prior to that, Mr. Collingsworth served as a board member of Texaco Canada Petroleum Inc. from July 1998 to October 2001 and was employed by Texaco from 1991 to 2001 in various management positions, including Senior Vice President of NGL Assets and Business Services from July 1998 to October 2001. Prior to joining Texaco, Mr. Collingsworth was director of feedstocks for Rexene Petrochemical Company from 1988 to 1991 and served in the MAPCO, Inc. organization from 1973 to 1988 in various capacities, including customer service and business development manager of the Mid-America and Seminole pipelines. Mr. Collingsworth currently serves on the board of directors of Martin Midstream Partners L.P.

Mr. Collingsworth brings a wealth of in-depth industry experience to the Partnership. Mr. Collingsworth has worked in all facets of the midstream and petrochemical industry for more than 40 years.

Stephen L. Cropper. Mr. Cropper joined the board of directors of our general partner in June 2011. Mr. Cropper held various positions during his 25-year career at The Williams Companies, Inc., including serving as the President and Chief Executive Officer of Williams Energy Services, a Williams operating unit involved in various energy-related businesses, until his retirement in 1998. Mr. Cropper served as a director of Energy Transfer Partners, L.P. from 2000 through 2005. Since Mr. Cropper’s retirement from The Williams Companies, Inc. in 1998, he has been a consultant and private investor and also served as a director of Sunoco Logistics Partners, L.P., NRG Energy, Inc., Berry Petroleum Company, and Rental Car Finance

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Corp., a subsidiary of Dollar Thrifty Automotive Group. Mr. Cropper currently serves on the board of directors of QuikTrip Corporation and Wawa Inc.

Mr. Cropper brings substantial experience in the energy business and in the marketing of energy products to the board. With his significant management and governance experience, Mr. Cropper provides important skills in identifying, assessing and addressing various business issues. As a director for other public companies, Mr. Cropper also provides cross board experience.

Bryan K. Guderian. Mr. Guderian joined the board of directors of our general partner in May 2012. Mr. Guderian has served as Senior Vice President of Business Development of WPX Energy, Inc. (“WPX”) since October 2014. Mr. Guderian served as Senior Vice President of Operations of WPX from August 2011 to October 2014. Mr. Guderian previously served as Vice President of the Exploration & Production unit of The Williams Companies, Inc. from 1998 until August 2011, where he had responsibility for overseeing international operations. Mr. Guderian has served as a director of Apco Oil & Gas International Inc., since 2002 and as a director of Petrolera Entre Lomas S.A. since 2003.

Mr. Guderian brings considerable upstream experience to the board including executive, operational and financial expertise from 30 years of petroleum industry involvement, the majority of which has been focused in exploration and production.

James C. Kneale. Mr. Kneale joined the board of directors of our general partner in May 2011. Mr. Kneale served as President and Chief Operating Officer of ONEOK, Inc., from January 2007, and ONEOK Partners, L.P., from May 2008, until his retirement in January 2010. After joining ONEOK in 1981, Mr. Kneale served in various other roles, including Chief Financial Officer from 1999 through 2006. Mr. Kneale also served as a director of ONEOK Partners, L.P. from 2006 until his retirement in January 2010.

Mr. Kneale brings extensive executive, financial and operational experience to the board. With nearly 30 years of experience in the natural liquids gas industry in numerous positions, Mr. Kneale provides valuable insight into our business and industry.

John T. Raymond. Mr. Raymond joined the board of directors of our general partner in August 2013. Mr. Raymond is the Founder and Majority Owner of The Energy & Minerals Group (“EMG”) of which he has been a Managing Partner and the Chief Executive Officer since its September 2006 inception. Mr. Raymond has held executive leadership positions with various energy companies, including President and Chief Executive Officer of Plains Resources Inc. (the predecessor entity of Vulcan Energy Corporation), President and Chief Operating Officer of Plains Exploration and Production Company and was a Director of Plains All American Pipeline, LP.

Mr. Raymond also currently serves a director of American Energy Ohio Holdings, LLC, Ferus Inc., Ferus Natural Gas Fuels Inc., Iron Ore Holdings, Lighthouse Oil & Gas GP, LLC, MarkWest Utica EMG, LLC, Medallion Midstream, LLC, Plains All American GP LLC and Tallgrass MLP GP LLC. Mr. Raymond manages various private investments through personally held Lynx Holdings, LLC.

Patrick Wade. Mr. Wade served as a member of the High Sierra board beginning in November 2008 and as a member of the board of directors of our general partner since 2012. Mr. Wade has 20 years of experience in the energy sector. In 2002, Mr. Wade co-founded Tiger Midstream Investments, a natural gas midstream development and investment company that was involved primarily in the Rocky Mountains. From 2005 to 2007, Mr. Wade was a Managing Director at Bear Energy LP, responsible for investments in natural gas midstream infrastructure, as well as contracting for a diverse portfolio of natural gas storage capacity. In 2008, Mr. Wade joined EMG as a Managing Director in the Houston office. EMG is the management company for a series of specialized private equity funds. EMG focuses on investing across various facets of the global natural resource industry including the upstream and midstream segments of the energy complex. EMG is the managing partner of EMG NGL HC LLC. Mr. Wade's primary focus is making direct investments across the natural resources industry. Mr. Wade served as a director of MarkWest Liberty Midstream & Resources from 2009 through 2011. In addition, Mr. Wade currently serves on the board of directors of Medallion Midstream, L.L.C., Ferus Inc., and Lodestar Energy Group, LLC.

Mr. Wade brings extensive financial and industry experience to the board. With 20 years of experience in the energy sector, Mr. Wade provides valuable insight into our business.

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Director Appointment Rights

The Limited Liability Company Agreement of NGL Energy Holdings LLC grants certain parties the right to designate a specified number of persons to serve on the board of directors. EMG NGL HC LLC has the right to designate two persons to serve on the board of directors, and has designated John T. Raymond and Patrick Wade. The Coady Group (which consists of certain entities controlled by Shawn W. Coady and Todd M. Coady) and the investors who formed the Partnership ("IEP Parties") (which consists of certain entities controlled by H. Michael Krimbill, and two other investors, one of whom is an employee of the Partnership) each have the right to designate one person to serve on the board of directors. The Coady Group has designated Shawn W. Coady and the IEP Parties have designated H. Michael Krimbill.

Board Leadership Structure and Role in Risk Oversight

The board of directors of our general partner believes that whether the offices of chairman of the board and chief executive officer are combined or separated should be decided by the board, from time to time, in its business judgment after considering relevant circumstances. The board of directors of our general partner currently does not have a chairman.

The board of directors and its committees regularly review material operational, financial, compensation and compliance risks with senior management. In particular, the audit committee is responsible for risk oversight with respect to financial and compliance risks and risks relating to our audit and independent registered public accounting firm. Our compensation committee considers risk in connection with its design and evaluation of compensation programs for our senior management. Each committee regularly reports to the board of directors.

Audit Committee

The board of directors of our general partner has established an audit committee. The audit committee assists the board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to, among other things:

- retain and terminate our independent registered public accounting firm;
- approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm; and
- establish policies and procedures for the pre-approval of all non-audit services and tax services to be rendered by our independent registered public accounting firm.

The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management, as necessary.

Mr. Collingsworth, Mr. Cropper, and Mr. Kneale currently serve on the audit committee, and Mr. Kneale serves as the chairman. The board of directors of our general partner has determined that Mr. Kneale is an "audit committee financial expert" as defined under SEC rules and that each member of the audit committee is financially literate. In compliance with the requirements of the NYSE, all of the members of the audit committee are independent directors, as defined in the applicable NYSE and Exchange Act rules.

Compensation Committee

The board of directors of our general partner has established a compensation committee. The compensation committee's responsibilities include the following, among others:

- establishing the general partner's compensation philosophy and objectives;
- approving the compensation of the Chief Executive Officer;
- making recommendations to the board of directors with respect to the compensation of other officers and directors; and
- reviewing and making recommendations to the board of directors with respect to incentive compensation and equity-based plans.

Mr. Cropper, Mr. Guderian, and Mr. Kneale currently serve on the compensation committee. Mr. Cropper serves as the chairman. The board of directors has determined that Mr. Cropper and Mr. Kneale are independent directors under applicable NYSE and Exchange Act rules. The NYSE does not require a listed publicly traded limited partnership to have a compensation committee consisting entirely of independent directors.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's board of directors and officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of beneficial ownership and reports of changes in beneficial ownership of our common units and other equity securities with the SEC. Directors, officers and greater than 10% unitholders are required by SEC regulations to furnish to us copies of all Section 16(a) forms they file with the SEC.

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations by our directors and officers, we believe that all reporting obligations of our general partner's directors and officers and our greater than 10% unitholders under Section 16(a) were satisfied during the year ended March 31, 2016, except for the purchase of stock by Shawn W. Coady on August 17, 2015 and by James Collingsworth on February 12, 2016 which were both late by one day. Also, a Form 3 for Robert W. Karlovich III, who became an executive officer on February 22, 2016, was not filed until March 9, 2016. Mr. Karlovich's receipt of a grant of restricted common units on February 22, 2016 was not reported on a Form 4 until March 10, 2016.

Corporate Governance

The board of directors of our general partner has adopted a Code of Ethics for the Chief Executive Officer and Senior Financial Officers, or Code of Ethics, that applies to the chief executive officer, chief financial officer, chief accounting officer, controller and all other senior financial and accounting officers of our general partner. Amendments to or waivers from the Code of Ethics will be disclosed on our website. The board of directors of our general partner has also adopted Corporate Governance Guidelines that outline important policies and practices regarding our governance and a Code of Business Conduct and Ethics that applies to the directors, officers and employees of our general partner and the Partnership.

We make available free of charge, within the "Governance" section of our website at http://www.nglenergypartners.com/governance, and in print to any unitholder who so requests, the Code of Ethics, the Corporate Governance Guidelines, the Code of Business Conduct and Ethics and the charters of the audit committee and the compensation committee of the board of directors of our general partner. Requests for print copies may be directed to Investor Relations at investorinfo@nglep.com or to Investor Relations, NGL Energy Partners LP, 6120 South Yale Avenue, Suite 805, Tulsa, Oklahoma 74136 or made by telephone at (918) 481-1119. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Meeting of Non-Management Directors and Communications with Directors

At each quarterly meeting of the audit committee and/or the board of directors of our general partner, our independent directors meet in an executive session without participation by management or non-independent directors. Mr. Kneale presides over these executive sessions.

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Unitholders or interested parties may communicate directly with the board of directors of our general partner, any committee of the board, any independent directors, or any one director, by sending written correspondence by mail addressed to the board, committee or director to the attention of our Secretary at the following address: Name of the Director(s), c/o Secretary, NGL Energy Partners LP, 6120 South Yale Avenue, Suite 805, Tulsa, Oklahoma 74136. Communications are distributed to the board, committee, or director as appropriate, depending on the facts and circumstances outlined in the communication.

Item 11. Executive Compensation

Compensation Discussion and Analysis

The year “2016” in the Compensation Discussion and Analysis and the summary compensation table refers to our fiscal year ended March 31, 2016.

Introduction

The board of directors of our general partner has responsibility and authority for compensation-related decisions for our executive officers. The board of directors has formed a compensation committee to develop our compensation program, to determine the compensation of our Chief Executive Officer, and to make recommendations to the board of directors regarding the compensation of our other executive officers. Our executive officers are also officers of our operating companies and are compensated directly by our operating companies. While we reimburse our general partner and its affiliates for all expenses they incur on our behalf, our executive officers do not receive any additional compensation for the services they provide to our general partner.

Our “named executive officers” for fiscal year 2016 were:

- H. Michael Krimbill–Chief Executive Officer
- Robert W. Karlovich III–Chief Financial Officer (effective February 22, 2016)
- James J. Burke–President
- Shawn W. Coady–President and Chief Operating Officer, Retail Division
- Vincent J. Osterman–President, Eastern Retail Propane Operations
- Atanas H. Atanasov–Chief Financial Officer and Treasurer (resigned effective February 5, 2016)

Compensation Philosophy

Our compensation philosophy emphasizes pay-for-performance, focused primarily on the ability to increase sustainable quarterly distributions to our unitholders. Pay-for-performance is based on a combination of our performance and the individual executive officer’s contribution to our performance. We believe this pay-for-performance approach generally aligns the interests of our executive officers with the interests of our unitholders, and at the same time enables us to maintain a lower level of cash compensation expense in the event our operating and financial performance do not meet our expectations.

Our executive compensation program is designed to provide a total compensation package that allows us to:

- Attract and retain individuals with the background and skills necessary to successfully execute our business strategies;
- Motivate those individuals to reach short-term and long-term goals in a way that aligns their interests with the interests of our unitholders; and
- Reward success in reaching those goals.

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Recent Achievements

Our compensation structure is designed to reward our officers for achieving above-market returns for our unitholders. Our achievements during the year ended March 31, 2016 included the following:

- Entered into an agreement with Saddlehorn Pipeline Company, LLC to combine pipeline projects to transport crude oil from Weld County, Colorado to Cushing Oklahoma, of which we will own a 37.5% undivided interest in the pipeline; and
- We sold our general partner interest in TLP for $350 million.

Compensation Highlights

- We paid no cash bonuses to our named executive officers during fiscal year 2016.
- The salaries of most of our named executive officers remain below the median of our benchmark peer group. This enables us to grant more performance-based compensation to maintain competitive total compensation packages.
- We introduced a new performance-based restricted unit program for which no payout will be made unless the return on our common units exceeds the median returns for a specified peer group over specified periods of time.

Factors Enhancing Alignment with Unitholder Interests

- Majority of officer pay is at risk incentive compensation based on annual financial performance and growth in unitholder value;
- Equity-based incentives are the largest single component of officer compensation;
- Certain of the officers' equity awards are subject to achievement of above-median total unitholder return relative to our performance peer group;
- No excise tax gross-ups; and
- Compensation committee engages an independent compensation adviser.

Compensation Setting Process

Our compensation program for our named executive officers supports our philosophy of pay-for-performance.

- Role of Management: Our Chief Executive Officer also provides periodic recommendations to the compensation committee and the board of directors regarding the compensation of our other named executive officers.
- Role of the Compensation Committee's Consultant: In carrying out its responsibilities for establishing, implementing and monitoring the effectiveness of our executive compensation philosophy, plans and programs, our compensation committee has the authority to engage outside experts to assist in its deliberations. During fiscal year 2016, the compensation committee received compensation advice and data from Pearl Meyer & Partners ("PM&P"). PM&P conducted a competitive review of the principal components of compensation for our executives, including our named executive officers. PM&P also provided input on peer group selection (compensation and performance peers), and short and long-term incentive plan design. The compensation committee reviewed the services provided by PM&P and determined that they are independent in providing executive compensation consulting services. In making this determination, the compensation committee noted that during fiscal year 2016:
PM&P did not provide any services to the Partnership or management other than compensation consulting services requested by or with the approval of the compensation committee;
PM&P does not provide, directly or indirectly through affiliates, any non-compensation services such as pension consulting or human resource outsourcing;
PM&P maintains a conflicts policy, which was provided to the compensation committee with specific policies and procedures designed to ensure independence;
Fees paid to PM&P by the Partnership during fiscal year 2016 were less than 1% of PM&P's total revenue;

None of the PM&P consultants working on Partnership matters had any business or personal relationship with compensation committee members;

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None of the PM&P consultants working on Partnership matters (or any consultants at PM&P) had any business or personal relationship with any executive officer of the Partnership; and
None of the PM&P consultants working on Partnership matters own Partnership interests.

The compensation committee continues to monitor the independence of its compensation consultant on a periodic basis. The compensation committee considered the recommendations provided by PM&P in the process of designing the fiscal year 2016 compensation program.

Elements of Executive Compensation

As part of our pay-for-performance approach to executive compensation, the compensation of our executive officers includes a significant component of incentive compensation based on our performance. The following table summarizes the primary elements of compensation in our executive compensation program:

			Objective Supported		
Element	Primary Purpose	How Amount Determined	Attract & Retain	Motivate & Pay for Performance	Unitholder Alignment
Base Salary	Fixed income to compensate executive officers for their level of responsibility, expertise and experience	Based on competition in the marketplace for executive talent and abilities	X		
Cash Bonus Awards	Rewards achievement of specific annual financial and operational performance goals Recognizes individual contributions to our performance	Based on the named executive officer's relative contribution to achieving or exceeding annual goals	X	X	X
Long-Term Equity Incentive Awards	Motivates and rewards the achievement of long-term performance goals, including increasing the market price of our common units and the quarterly distributions to our unitholders Provides a forfeitable long-term incentive to encourage executive retention	Based on the named executive officer's expected contribution to long-term performance goals	X	X	X

Base Salary

The compensation committee periodically reviews the base salaries of our named executive officers and may recommend adjustments as necessary. We do not make automatic annual adjustments to base salary.

- Mr. Krimbill's initial base salary of $120,000 was originally determined as part of the negotiations for our formation transactions. In setting the base salaries, the parties considered various factors, including the compensation needed to attract or retain the officers, the historical compensation of the officers, and each officer's expected individual contribution to our performance. At the request of Mr. Krimbill, the parties agreed that he should receive a lower base salary than our other executive officers at the time because, as our Chief Executive Officer, a significant portion of his compensation should be performance-based, to further align his interests with the interests of our unitholders. In February 2012, the base salary of Mr. Krimbill was reduced to $60,000, based on our operating and financial performance as a result of an unusually warm winter. The base salary of Mr. Krimbill was restored to $120,000 effective November 12, 2012. Effective July 1, 2014, the Board of

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Directors increased Mr. Krimbill's salary to $350,000, in consideration of the fact that his salary was low relative to the benchmark peer group (and remains below the 25th percentile of the peer group).

- Mr. Karlovich's base salary of $400,000 was negotiated prior to his joining our management team in February 2016.
- Mr. Burke's base salary of $353,000 became effective on June 19, 2012 when Mr. Burke joined our management team upon completion of our merger with High Sierra. Mr. Burke's base salary was increased to $375,000 in July 2013 and to $384,000 in June 2014. Mr. Burke was given a lower salary increase than the other named executive officers, based on the fact that his salary is higher relative to the benchmark peer group than the other named executive officers (his current salary is close to the 50th percentile of the peer group).
- Dr. Coady's base salary of $300,000 was determined as part of the negotiations for our formation transactions. In February 2012, the base salary of Dr. Coady was reduced to $200,000 based on our operating and financial performance as a result of an unusually warm winter. The base salary of Dr. Coady was restored to $300,000 effective November 12, 2012. Dr. Coady's base salary was increased to $315,000 in July 2014, in consideration of the fact that his salary was low relative to the benchmark peer group.
- Mr. Osterman's initial base salary of $125,000 was negotiated at the time Mr. Osterman joined our management team upon completion of our acquisition of Osterman Propane. Mr. Osterman's salary was increased to $200,000 in January 2013 and to $250,000 in July 2013, in consideration of the fact that his salary was low relative to the benchmark peer group.
- Mr. Atanasov's base salary of $195,000 was negotiated prior to his joining our management team in November 2011. The base salary of Mr. Atanasov was increased to $250,000 in July 2013 and to $300,000 in July 2014, in consideration of the fact that his salary was low relative to the benchmark peer group.

Cash Bonus Awards

None of the named executive officers is subject to a formal cash bonus plan, and any cash bonuses are at the discretion of the Compensation Committee or the Board of Directors, (in the case of Mr. Krimbill) or the Compensation Committee (in the case of the other named executive officers).

Long-Term Equity Incentive Awards

Certain restricted units granted to the named executive officers vest in tranches, contingent only on the continued service of the recipient through the vesting date (the "Service Awards"). The following table summarizes grants of Service Award units granted, vested and/or forfeited during fiscal year 2016 with respect to the named executive officers:

	Unvested Units at March 31, 2015	Units Granted	Units Vested	Units Forfeited	Unvested Units at March 31, 2016
H. Michael Krimbill (1)	—	213,573	(71,191)	—	142,382
Robert W. Karlovich III (2)	—	75,000	—	—	75,000
James J. Burke (3)	45,000	25,000	(25,000)	—	45,000
Shawn W. Coady (3)	45,000	25,000	(25,000)	—	45,000
Vincent J. Osterman (3)	45,000	25,000	(25,000)	—	45,000
Atanas H. Atanasov (4)	36,000	8,333	(20,333)	(24,000)	—

(1) Mr. Krimbill was granted 213,573 Service Awards on April 23, 2015.
(2) Mr. Karlovich was granted 75,000 Service Awards on February 22, 2016.
(3) Mr. Burke, Dr. Coady and Mr. Osterman were each granted 10,000 Service Awards on July 1, 2015 and 15,000 Service Awards on February 18, 2016.
(4) Mr. Atanasov was granted 8,333 Service Awards on July 1, 2015 and forfeited all outstanding Service Awards upon his resignation from employment.

The number of Service Award units granted to Mr. Krimbill was calculated based on the median value of equity award units granted to chief executive officers in the benchmark peer group.

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The Service Award units granted in July 2015 were intended as discretionary bonuses for performance during fiscal year 2015.

The Service Award units granted to Mr. Karlovich were negotiated prior to his joining our management team in February 2016.

The Service Award units granted to in February 2016 were intended for retention.

The following table summarizes the vesting dates of the unvested Service Award units at March 31, 2016:

	Service Award Units by Vesting Date			Total Unvested Units
	July 1, 2016	July 1, 2017	July 1, 2018	at March 31, 2016
H. Michael Krimbill	71,191	71,191	—	142,382
Robert W. Karlovich III	25,000	25,000	25,000	75,000
James J. Burke	30,000	15,000	—	45,000
Shawn W. Coady	30,000	15,000	—	45,000
Vincent J. Osterman	30,000	15,000	—	45,000

During April 2015, the Partnership granted awards that are contingent both on the continued service of the recipients through the vesting date and also on the performance of our common units relative to the performance of other entities in the Alerian MLP Index (the “Index”) over specified periods of time (the “Performance Awards”).

The Performance Awards represent hypothetical units and are not actual common units. The Performance Awards settle in common units rather than cash. The right to receive common units with respect to the Performance Awards depends on (i) the level of total unitholder return attained by us over the applicable performance periods, as measured against our peer group and as described in the Performance Unit Agreement, provided that the number of common units that may be earned in respect of the Performance Awards will either be 0% of the Performance Awards, for performance at anything less than the 50th percentile of the performance peer group, or in a range of 50% to 200% of the Performance Awards, for performance from the 50th percentile to the 90th percentile of the performance peer group over the same performance period (such number of earned Performance Awards are referred to, and defined in the Performance Unit Agreement, as, "Earned Performance Awards"), and (ii) the satisfaction of a continued service requirement.

The following table summarizes the maximum number of units that could vest on the Performance Awards granted to each named executive officer:

	Maximum Performance Award Units by Vesting Date			
	July 1, 2015	July 1, 2016	July 1, 2017	Total
H. Michael Krimbill	142,382	142,382	142,382	427,146
Atanas H. Atanasov	24,000	24,000	24,000	72,000
James J. Burke	30,000	30,000	30,000	90,000
Shawn W. Coady	30,000	30,000	30,000	90,000
Vincent J. Osterman	30,000	30,000	30,000	90,000

The number of Performance Award units that will vest is contingent on the performance of our common units relative to the performance of the other entities in the Index. Performance will be calculated based on the return on our common units (including changes in the market price of the common units and distributions paid during the performance period) relative to the returns on the common units of the other entities in the Index. Performance will be measured over the following periods:

Vesting Date of Tranche	Performance Period for Tranche
July 1, 2015	July 1, 2012 through June 30, 2015
July 1, 2016	July 1, 2013 through June 30, 2016
July 1, 2017	July 1, 2014 through June 30, 2017

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The following table summarizes the percentage of the maximum Performance Award units that will vest depending on the percentage of entities in the Index that NGL outperforms:

Our Relative TUR Percentile Ranking	Payout (% of Target Units)
Less than 50th percentile	—%
Between the 50th and 75th percentile	50%–100%
Between the 75th and 90th percentile	100%–200%
Above the 90% percentile	200%

The Performance Award units were granted in consideration of the fact that the base salaries and the service-based equity awards for the named executive officers are in most cases below the median value for officers in their respective peer groups. The Compensation Committee believes that if the performance of NGL's common units falls below the median performance of the Index, the named executive officers should receive lower compensation than their peers, but that if the performance of NGL's common units exceeds the median of the Index, the compensation of the named executive officers should be increased.

Severance and Change in Control Benefits

We do not provide any severance or change of control benefits to our named executive officers. The board of directors has the option to accelerate the vesting of the restricted units in the event of a change in control of the Partnership, although it is not under any obligation to do so. If the board of directors were to exercise its discretion to accelerate the vesting of restricted units upon a change in control, the value of such units would be the same as reported in the "Outstanding Equity Awards at March 31, 2016" table below.

401(k) Plan

We have established a defined contribution 401(k) plan to assist our eligible employees in saving for retirement on a tax-deferred basis. The 401(k) plan permits all eligible employees, including our named executive officers, to make voluntary pre-tax contributions to the plan, subject to applicable tax limitations. We make a maximum employer matching contribution equal to 3.5% of the employee's eligible compensation (as defined in the plan) that is not in excess of 6% of the employee's eligible compensation (subject to annual Internal Revenue Service contribution limits). Our matching contributions prior to January 1, 2015 vest over 5 years and, effective January 1, 2015, our matching contributions vest over 2 years.

Other Benefits

We do not maintain a defined benefit or pension plan for our executive officers, because we believe such plans primarily reward longevity rather than performance. We provide a basic benefits package available to substantially all full-time employees, which includes a 401(k) plan and medical, dental, vision, disability and life insurance.

Other Officers

Certain officers who have leadership roles within our individual business units, but who are not executive officers, participate in formulaic bonus programs that are based on the performance of the individual business units with which they are involved. In most cases, similar programs were in place prior to our acquisition of the businesses, and we have left the programs substantially intact.

Competitive Review and Fiscal Year 2016 Compensation Program

During fiscal year 2016, PM&P conducted a competitive review of our executive compensation program and provided input to the compensation committee regarding competitive compensation levels and compensation program design. In order to provide guidance to the compensation committee regarding competitive rates of compensation, PM&P collected pay data from the following sources:

- Compensation surveys including data from published compensation surveys representative of other energy industry and broader general industry companies with revenues of between $1 billion and $6 billion; and

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- Peer group data including pay data from 10-K and proxy filings for a group of 20 publicly traded midstream oil & gas partnerships of similar size and scope to us.

Compensation Peer Group Companies

AmeriGas Partners LP	Enbridge Energy Partners, L.P.	Crosstex Energy LP
Ferrellgas Partners LP	NuStar Energy L.P.	DCP Midstream Partners LP
Star Gas Partners, L.P.	Targa Resources Partners LP	Martin Midstream Partners LP
Suburban Propane Partners, L.P.	Buckeye Partners, L.P.	Regency Energy Partners LP
ONEOK Partners, L.P.	Genesis Energy LP	Boardwalk Pipeline Partners, LP
Kinder Morgan Energy Partners, L.P.	Crestwood Midstream Partners LP	Western Gas Partners LP
Williams Partners L.P.	Magellan Midstream Partners LP	

PM&P defines “market” as the combination of survey data and peer group data. As described above, the Compensation Committee considered this data in establishing salaries for fiscal year 2016 and in determining the number of Service Award and Performance Award units to grant to the named executive officers.

Employment Agreements

We do not have employment agreements with any of our named executive officers.

Deductibility of Compensation

We believe that the compensation paid to the named executive officers is generally fully deductible for federal income tax purposes. We are a limited partnership and we do not meet the definition of a “corporation” subject to deduction limitations under Section 162(m) of the Internal Revenue Code of 1986, as amended.

Compensation Committee Report

The Compensation Committee of the board of directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis set forth above with management. Based on this review and discussion, the Compensation Committee recommended to the board of directors of our general partner that the Compensation Discussion and Analysis be included in this Annual Report.

Members of the Compensation Committee:

Stephen L. Cropper (Chairman)
Bryan K. Guderian
James C. Kneale

Relation of Compensation Policies and Practices to Risk Management

Our compensation arrangements contain a number of design elements that serve to minimize the incentive for taking excessive or inappropriate risk to achieve short-term, unsustainable results. This includes using restricted unit grants as a significant element of the executive compensation, as the restricted units are designed to reward the executives based on the long-term performance of the Partnership. In combination with our risk-management practices, we do not believe that risks arising from our compensation policies and practices for our employees are reasonably likely to have a material adverse effect on us.

Compensation Committee Interlocks and Insider Participation

During fiscal year 2016, Stephen L. Cropper, Bryan K. Guderian, and James C. Kneale served on the Compensation Committee. None of these individuals is an employee or an officer of our general partner. As described under Part I, Item 13–"Transactions With Related Persons," Mr. Guderian is an executive officer of WPX, and we entered into certain transactions with WPX during fiscal year 2016. Shawn W. Coady is an executive officer and a member of the board of directors of our general partner. Dr. Coady also serves on the board of directors of HOH, a family-owned company, and in this capacity Dr. Coady participates in the compensation setting process of the HOH board of directors.

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Summary Compensation Table for 2016

The following table summarizes the compensation earned by our named executive officers for fiscal years 2014 through 2016.

Name and Position	Fiscal Year	Salary ($)	Bonus (1) ($)	Restricted Unit Awards (Service and Performance Awards) (2) ($)	All Other Compensation (3) ($)	Total ($)
H. Michael Krimbill	2016	350,000	—	8,319,437	7,539	8,676,976
Chief Executive Officer	2015	292,500	—	—	9,319	301,819
	2014	117,693	475,000	—	6,493	599,186
Robert W. Karlovich III	2016	30,769	—	419,250	—	450,019
Chief Financial Officer						
James J. Burke (4)	2016	375,000	—	1,047,241	27,898	1,450,139
President	2015	381,750	—	602,270	26,467	1,010,487
	2014	367,385	450,000	—	24,651	842,036
Shawn W. Coady	2016	315,000	—	1,047,241	9,329	1,371,570
President and Chief Operating	2015	311,250	—	1,331,501	19,153	1,661,904
Officer, Retail Division	2014	300,000	200,000	—	19,630	519,630
Vincent J. Osterman (5)	2016	250,000	—	1,047,241	30,906	1,328,147
President, Eastern Retail	2015	250,000	—	1,331,501	31,763	1,613,264
Propane Operations						
Atanas H. Atanasov (6)	2016	265,385	50,000	752,755	8,885	1,077,025
Former Chief Financial Officer	2015	287,500	—	864,664	9,346	1,161,510
	2014	232,500	195,000	259,696	7,038	694,234

(1) Amounts for fiscal year 2014 include discretionary bonuses paid in fiscal year 2014 based on contributions of the individuals since the time they joined the Partnership through the date of the bonus and based on expectations of future performance.

(2) The fair values of the restricted units shown in the table above were calculated based on the closing market prices of our common units on the grant dates, with adjustments made to reflect the fact that the restricted units are not entitled to distributions during the vesting period. The impact of the lack of distribution rights during the vesting period was estimated using the value of the most recent distribution prior to the grant date and assumptions that a market participant might make about future distribution growth. This calculation of fair value is consistent with the provisions of Accounting Standards Codification 718 Stock Compensation. The following table summarizes these amounts:

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Name	Service Award Grant Date Fair Value	Performance Award Grant Date Fair Value	Total Grant Date Fair Value	Performance Awards at Maximum Value
H. Michael Krimbill	$4,624,567	$3,694,870	$8,319,437	$7,389,740
Robert W. Karlovich III	419,250	—	419,250	—
James J. Burke	413,050	650,591	1,063,641	1,301,181
Shawn W. Coady	413,050	650,591	1,063,641	1,301,181
Vincent J. Osterman	413,050	650,591	1,063,641	1,301,181
Atanas H. Atanasov	245,949	520,472	766,421	1,040,945

(3) The amounts in this column include matching contributions to our 401(k) plan. Amounts for Mr. Burke include a club membership and a car allowance. Amounts for Dr. Coady include the incremental cost of the use of a company car, including depreciation, maintenance, insurance, and fuel. Amounts for Mr. Osterman include propane provided to him and to members of his family (valued for this purpose at the cost of the propane to NGL). The following table summarizes these amounts:

Name	Fiscal Year	401(k) Match	Car Allowance	Club Membership	Propane	Total Other Compensation
James J. Burke	2016	$10,774	$ 9,000	$ 8,124	$ —	$ 27,898
	2015	9,343	9,000	8,124	—	26,467
	2014	7,527	9,000	8,124	—	24,651
Shawn W. Coady	2016	9,329	—	—	—	9,329
	2015	9,796	9,357	—	—	19,153
	2014	8,750	10,880	—	—	19,630
Vincent J. Osterman	2016	4,038	—	—	26,868	30,906
	2015	18,468	—	—	13,295	31,763

(4) Mr. Burke joined our management team upon completion of our merger with High Sierra on June 19, 2012.
(5) Mr. Osterman was not a named executive officer prior to fiscal year 2015.
(6) Mr. Atanasov resigned as Chief Financial Officer effective February 5, 2016.

Restricted Unit Awards

During fiscal year 2016, the Committee granted awards for which units vest at specified dates, contingent only on the continued service of the recipient through the service date (the “Service Awards”) and awards that vest at specific dates, contingent on both the performance of our common units relative to the performance of other entities and on the continued service of the recipient through the vesting (the “Performance Units”).

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2016 Grants of Plan Based Awards Table

The following table summarizes the number of restricted Service and Performance Award units granted to our named executive officers, and their grant date fair values:

Name	Grant Date	Total Number of Service Award Units	Estimated Future Payouts Under Performance Awards (1) Threshold (#) 50%	Target (#) 100%	Maximum (#) 200%	Grant Date Fair Value of Service Award Units ($)(2)(3)
H. Michael Krimbill	April 23, 2015	213,573				4,624,567
	April 23, 2015		106,786	213,573	427,146	3,694,870
Robert W. Karlovich III	February 22, 2016	75,000				419,250
James J. Burke	April 17, 2015		22,500	45,000	90,000	650,591
	July 1, 2015	10,000				295,150
	February 18, 2016	15,000				117,900
Shawn W. Coady	April 17, 2015		22,500	45,000	90,000	650,591
	July 1, 2015	10,000				295,150
	February 18, 2016	15,000				117,900
Vincent J. Osterman	April 17, 2015		22,500	45,000	90,000	650,591
	July 1, 2015	10,000				295,150
	February 18, 2016	15,000				117,900
Atanas H. Atanasov	April 17, 2015		18,000	36,000	72,000	520,472
	July 1, 2015	8,333				245,949

(1) Amounts reported in the (a) “Threshold” column reflect the threshold number of Performance Awards (at 50% of target) that may be earned (assuming a relative TUR at the 50th percentile), (b) “Target” column reflect the target number of performance awards, or 100%, that may be earned (assuming a relative TUR at the 75th percentile) and (c) “Maximum” column reflect 200% of the target performance awards that may be earned (assuming a relative TUR greater than the 90th percentile). The number of common units actually received by a named executive officer with respect to a Performance Award may vary based on the Partnership’s relative TUP as compared to the TUR of the performance peer group. The Performance Awards are described above under “Long-Term Equity Incentive Awards” in the Compensation Discussion and Analysis.

(2) The disclosure reflects the aggregate grant date fair value of the Performance Awards, computed in accordance with FASB ASC Topic 718 based on probably achievement of the performance conditions, which is consistent with the estimate of aggregate compensation to be recognized over the service period, excluding the effect of estimated forfeitures.

(3) The fair value of the restricted Service Award units shown in the table above were calculated based on the closing market price of our common units on the grant dates, with adjustments made to reflect the fact that restricted units are not entitled to distributions during the vesting period.

We record in our consolidated financial statements the expense for each tranche on a straight-line basis over the period beginning with the vesting of the previous tranche and ending with the vesting of the tranche. We adjust the cumulative expense recorded through each reporting date using the estimated fair value of the awards at the reporting date.

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Outstanding Equity Awards at March 31, 2016

The following table summarizes the number of unvested Service Award and Performance Awards outstanding and their fair values at March 31, 2016:

	Service Awards		Performance Awards	
Name	Number of Units That Have Not Yet Vested #(1)	Market Value of Units that Have Not Vested ($)(2)	Number of Units That Have Not Yet Vested #(3)	Market Value of Units that Have Not Vested ($)(2)
H. Michael Krimbill	142,382	1,070,713	142,382	1,070,713
Robert W. Karlovich III	75,000	564,000	—	—
James J. Burke	45,000	338,400	30,000	225,600
Shawn W. Coady	45,000	338,400	30,000	225,600
Vincent J. Osterman	45,000	338,400	30,000	225,600
Atanas H. Atanasov (4)	N/A	N/A	N/A	N/A

(1) Reflects Service Awards that have not vested and are held by each named executive officer.

(2) Calculated based on the closing market price of our common units at March 31, 2016 of $7.52. No adjustments were made to reflect the fact that the restricted units are not entitled to distributions during the vesting period.

(3) Reflects the target number of Performance Awards granted to each named executive officer that have not vested. Vesting of the Performance Awards are contingent upon our relative TUR as measured against the performance peer group and satisfaction of a continued service requirement.

(4) Mr. Atanasov resigned effective February 5, 2016 resulting in the forfeiture of his Service Awards and Performance Awards. As a result, Mr. Atanasov did not have any outstanding equity awards as of March 31, 2016.

2016 Units Vested

During fiscal year 2016, certain of the restricted Service Award units and Performance Award units vested. The following table summarizes the value of the awards on the vesting date which was calculated based of the closing market price per common unit on the vesting dates.

	Service Awards		Performance Awards	
Name	Number of Units Acquired on Vesting	Value Realized on Vesting ($)	Number of Units Acquired on Vesting	Value Realized on Vesting ($)
H. Michael Krimbill	71,191	2,174,885	108,014	3,299,828
Robert W. Karlovich III	—	—	—	—
James J. Burke	25,000	717,100	22,759	695,287
Shawn W. Coady	25,000	717,100	22,759	695,287
Vincent J. Osterman	25,000	717,100	22,759	695,287
Atanas H. Atanasov	20,333	582,300	18,207	556,224

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Upon vesting, certain of the named executive officers elected for us to remit payments to taxing authorities in lieu of issuing common units. The following table summarizes the number of common units issued and the number of common units withheld for taxes:

Name	Number of Units Issued	Number of Units Withheld	Total
H. Michael Krimbill	128,226	50,979	179,205
James J. Burke	28,357	19,402	47,759
Shawn W. Coady	27,679	20,080	47,759
Vincent J. Osterman	26,805	20,954	47,759
Atanas H. Atanasov	24,468	14,072	38,540

Subsequent to vesting, regularly-scheduled distributions were paid on the common units. The following table summarizes the distributions paid during fiscal year 2015 on the common units that vested and were issued during fiscal year 2016:

Name	Distributions
H. Michael Krimbill	$ 245,232
James J. Burke	50,854
Shawn W. Coady	49,502
Vincent J. Osterman	47,919
Atanas H. Atanasov	44,012

Director Compensation

Officers or employees of our general partner and its affiliates who also serve as directors do not receive additional compensation for their service as a director of our general partner. Each director who is not an officer or employee of our general partner or its affiliates receives the following cash compensation for his board service:

- an annual retainer of $60,000;
- an annual retainer of $10,000 for the chairman of the audit committee; and
- an annual retainer of $5,000 for each member of the audit committee other than the chairman.

In addition, each director who is not an officer or an employee of our general partner has been granted awards of restricted units. In April 2015, such directors were granted 15,000 restricted units that vest in tranches of 5,000 units each on July 1, 2015, July 1, 2016, and July 1, 2017.

All of our directors are also reimbursed for all out-of-pocket expenses incurred in connection with attending board or committee meetings. Each director is indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

Director Compensation for Fiscal Year 2016

The following table summarizes the compensation earned during fiscal year 2016 by each director who is not an officer or employee of our general partner or its affiliates:

Name	Fees Earned or Paid in Cash ($)	Restricted Unit Awards ($)	Total ($)
James M. Collingsworth	70,000	324,800	394,800
Stephen L. Cropper	75,000	324,800	399,800
Bryan K. Guderian	65,000	324,800	389,800

James C. Kneale	70,000	324,800	394,800

During fiscal year 2016, a tranche of 5,000 units vested for each of these directors. Subsequent to the vesting, these individuals received distributions of $1.91 on each of the vested units.

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As of March 31, 2016, each of the directors listed in the table above has 10,000 unvested restricted units.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

Security Ownership of Certain Beneficial Owners and Management

The following table summarizes the beneficial ownership, as of May 20, 2016 of our common units by:

- each person or group of persons known by us to be a beneficial owner of more than 5% of our outstanding common units;
- each director of our general partner;
- each named executive officer of our general partner; and
- all directors and executive officers of our general partner as a group.

Beneficial Owners	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (1)	
5% or greater unitholders (other than officers and directors):			
Oppenheimer Funds, Inc. (2)	10,745,300	10.32	%
Magnum NGL HoldCo LLC (3)	7,396,973	7.10	%
ALPS Advisors, Inc. (4)	7,202,476	6.91	%
Salient Capital Advisors, LLC (5)	6,286,363	6.03	%
Directors and named executive officers:			
Atanas H. Atanasov	54,189	*	
James J. Burke (6)	324,642	*	
Shawn W. Coady (7)	2,531,910	2.43	%
James M. Collingsworth (8)	46,750	*	
Stephen L. Cropper (9)	35,000	*	
Bryan K. Guderian	32,500	*	
Robert W. Karlovich III	25,000	*	
James C. Kneale (10)	32,000	*	
H. Michael Krimbill (11)	1,877,820	1.87	%
Vincent J. Osterman (12)	3,972,900	3.81	%
John T. Raymond (13)	176,634	*	
Patrick Wade	—	—	
All directors and executive officers as a group (11 persons) (14)	9,109,345	8.74	%

* Less than 1.0%

(1) Based on 104,169,573 common units outstanding at May 23, 2016.

(2) The mailing address for OppenheimerFunds, Inc. is 225 Liberty Street, New York, NY 10281. OppenheimerFunds, Inc. reported shared voting and dispositive power with respect to all common units beneficially owned. This information related to OppenheimerFunds, Inc. is based upon its Schedule 13G/A filed with the SEC on April 8, 2016.

(3) The mailing address for Magnum NGL HoldCo LLC is 2603 Augusta, Suite 900, Houston, TX 77057. Magnum NGL HoldCo LLC reported shared voting and dispositive power with respect to all common units beneficially owned. This information related to Magnum NGL HoldCo LLC is based upon its Schedule 13G filed with the SEC on February 27, 2015.

(4) The mailing address for ALPS Advisors, Inc. is 1290 Broadway, Suite 1100, Denver, CO 80203. ALPS Advisors, Inc. reported shared voting and dispositive power with respect to all common units beneficially owned. This

information related to ALPS Advisors, Inc. is based upon its Schedule 13G filed with the SEC on February 3, 2016.

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(5) The mailing address for Salient Capital Advisors, LLC is 4265 San Felipe, 8th Floor, Houston, TX 77027. Salient Capital Advisors, LLC reported shared voting and dispositive power with respect to all common units beneficially owned. This information related to Salient Capital Advisors, LLC is based upon its Schedule 13G filed with the SEC on January 12, 2016.

(6) Mr. Burke owns 290,770 of these common units which includes 30,000 units that will vest on July 1, 2016, which were reported on Mr. Burke's most recent Form 4, but does not include 15,000 unvested units which were reported on Mr. Burke's most recent Form 4. Impact Development, LLC owns 33,872 of these common units. Impact Development, LLC is solely owned by James J. Burke, who may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. Impact Development, LLC also owns a 2.87% interest in our general partner.

(7) Dr. Shawn W. Coady owns 52,019 of these common units which includes 30,000 units that will vest on July 1, 2016, which were reported on Dr. Coady's most recent Form 4. SWC Family Partnership LP owns 2,320,391 of these common units. SWC Family Partnership LP is solely owned by SWC General Partner, LLC, of which Dr. Coady is the sole partner. Dr. Coady may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. The 2012 Shawn W. Coady Irrevocable Insurance Trust, which was established for the benefit of Shawn W. Coady's children, owns 135,000 of these common units. Dr. Coady may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. The Tara Nicole Coady Trust II, of which the reporting person is the trustee, owns 12,250 common units. The Colleen Blair Coady Trust, of which the reporting person is the trustee, owns 12,250 common units. Dr. Coady also owns a 12.27% interest in our general partner through Coady Enterprises, LLC, of which he owns 100% of the membership interests.

(8) Mr. Collingsworth owns 44,500 of these common units which includes 5,000 units that will vest on July 1, 2016, which were reported on Mr. Collingsworth's most recent Form 4, but does not include 5,000 unvested units which were reported on Mr. Collingworth's most recent Form 4. Mr. Collingsworth holds 2,000 of these common units jointly with his spouse, Cindy Collingsworth. Cindy Collingsworth and her sister jointly own 2,250 of these common units.

(9) Mr. Cropper owns 10,000 of these common units which includes 5,000 units that will vest on July 1, 2016, which were reported on Mr. Cropper's most recent Form 4, but does not include 5,000 unvested units which were reported on Mr. Cropper's most recent Form 4. The Donna L. Cropper Living Trust, of which Stephen L. Cropper and his spouse, Donna L. Cropper, are the trustees, owns 25,000 of these common units.

(10) Mr. Kneale owns 5,000 of these common units which includes 5,000 units that will vest on July 1, 2016, which were reported on Mr. Kneale's most recent Form 4, but does not include 5,000 unvested units which were reported on Mr. Kneale's most recent Form 4. The Suzanne and Jim Kneale Living Trust, of whom Mr. Kneale and his wife are trustees, owns 27,000 of these common units.

(11) Mr. H. Michael Krimbill owns 489,417 of these common units which includes 71,191 units that will vest on July 1, 2016, which were reported on Mr. Krimbill's most recent Form 4, but does not include 71,191 unvested units which were reported on Mr. Krimbill's most recent Form 4. Krim2010, LLC owns 904,484 of these common units. Krimbill Enterprises LP, H. Michael Krimbill and James E. Krimbill own 90.89%, 4.05%, and 5.06% of Krim2010, LLC, respectively. Krimbill Enterprises LP owns 120,000 of these common units. Krimbill Enterprises LP is controlled by H. Michael Krimbill via his ownership of its general partner, Krimbill Holding Company. H. Michael Krimbill may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. KrimGP2010 LLC owns 363,555 of these common units. KrimGP2010 LLC is solely owned by H. Michael Krimbill.
H. Michael Krimbill may be deemed to have sole voting and investment power over these units.
H. Michael Krimbill also owns a 14.81% interest in our general partner through KrimGP2010, LLC, of which he owns 100% of the membership interests and Krimbill Capital Group, LLC, which is owned 100% by the H. Michael Krimbill Revocable Trust.

(12) Mr. Osterman owns 118,263 of these common units which includes 30,000 units that will vest on July 1, 2016, which were reported on Mr. Osterman's most recent Form 4. The remaining common units are owned by AO Energy, Inc. (110,587 common units), E. Osterman, Inc. (394,350 common units), E. Osterman Gas Services, Inc. (301,700 common units), E. Osterman Propane, Inc. (669,300 common units), Milford Propane, Inc. (559,784 common units), Osterman Family Foundation (122,016 common units), Osterman Propane, Inc. (1,445,850 common units), Propane Gas, Inc. (36,450 common units) and Saveway Propane Gas Service, Inc. (214,600 common units). Each of these holding entities may be deemed to have sole voting and investment power over its own common units and Propane Gas, LLC, as sole shareholder of Propane Gas, Inc., may be deemed to have sole voting and investment power over those common units. Vincent J. Osterman is a director, executive officer and shareholder or member of each of these entities and may be deemed to have sole voting and investment power over 787,563 common units and shared voting and investment power

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(with his father, Ernest Osterman) over 3,185,337 common units, but disclaims beneficial ownership except to the extent of his pecuniary interest therein. Vincent J. Osterman also owns a 1.65% interest in our general partner through VE Properties XI LLC.

(13) EMG NGL HC, LLC owns all of the 176,634 common units. John T. Raymond is the Chief Executive Officer and Managing Partner of NGP MR GP LLC, the general partner of NGP MR, LP, the general partner of NGP Midstream & Resources, LLC, a member holding a majority interest in EMG NGL HC LLC. John T. Raymond may be deemed to have shared voting and investment power over these units, but disclaims beneficial ownership except to the extent of his pecuniary interest therein. EMG I NGL GP Holdings, LLC, an affiliate of EMG NGL HC LLC, owns a 5.73% interest in our general partner. EMG II NGL GP Holdings, LLC, an affiliate of EMG NGL HC LLC, owns a 5.36% interest in our general partner.

(14) The directors and executive officers of our general partner also collectively own a 48.11% interest in our general partner.

Unless otherwise noted, each of the individuals listed above is believed to have sole voting and investment power with respect to the units beneficially held by them. The mailing address for each of the officers and directors of our general partner listed above is 6120 South Yale Avenue, Suite 805, Tulsa, Oklahoma 74136.

Securities Authorized for Issuance Under Equity Compensation Plan

The following table summarizes information regarding the securities that may be issued under the LTIP at March 31, 2016.

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuances Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)(1)
Equity Compensation Plans Approved by Security Holders	—	—	—
Equity Compensation Plans Not Approved by Security Holders (2)	2,297,132	—	4,640,927
Total	2,297,132	—	4,640,927

(1) The number of common units that may be delivered pursuant to awards under the LTIP is limited to 10% of our issued and outstanding common units. The maximum number of common units deliverable under the LTIP automatically increases to 10% of the issued and outstanding common units immediately after each issuance of common units, unless the plan administrator determines to increase the maximum number of units deliverable by a lesser amount.

(2) Our general partner adopted the LTIP in connection with the completion of our initial public offering ("IPO") in May 2011. The adoption of the LTIP did not require the approval of our unitholders.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Our directors, executive officers, and greater than 5% unitholders collectively own an aggregate of 40,740,457 common units, representing an aggregate 38.70% limited partner interest in us. In addition, our general partner owns a 0.1% general partner interest in us and all of our incentive distribution rights ("IDRs").

Distributions and Payments to Our General Partner and Its Affiliates

Our general partner and its affiliates do not receive any management fee or other compensation for the management of our business and affairs, but they are reimbursed for all expenses that they incur on our behalf, including general and administrative expenses. Our general partner determines the amount of these expenses. In addition, our general partner owns the 0.1% general partner interest and all of the IDRs. Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement.

The following table summarizes the distributions and payments to be made by us to our directors, officers, and greater than 5% owners and our general partner in connection with our ongoing operation and any liquidation. These distributions and

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payments were determined by and among affiliated entities before our IPO and, consequently, are not the result of arm's length negotiations.

Operation Stage

Distributions of available cash to our directors, officers, and greater than 5% owners and our general partner	We generally make cash distributions 99.9% to our unitholders pro rata, including our directors, officers, and greater than 5% owners as the holders of an aggregate 40,740,457 common units, and 0.1% to our general partner. In addition, when distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner is entitled to increasing percentages of the distributions, up to 48.1% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the same quarterly distribution on all of our outstanding units for four quarters that we paid in May 2016 ($0.39 per unit), our general partner would receive an annual distribution of $0.3 million on its general partner interest and incentive distribution rights, and our directors, officers, and greater than 5% owners would receive an aggregate annual distribution of $72.2 million on their common units. If our general partner elects to reset the target distribution levels, it will be entitled to receive common units and to maintain its general partner interest.
Payments to our general partner and its affiliates	Our general partner and its affiliates do not receive any management fee or other compensation for the management of our business and affairs, but they are reimbursed for all expenses that they incur on our behalf, including general and administrative expenses. As the sole purpose of the general partner is to act as our general partner, substantially all of the expenses of our general partner are incurred on our behalf and reimbursed by us or our subsidiaries. Our general partner determines the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its IDRs will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Transactions With Related Persons

SemGroup

SemGroup holds an 11.78% ownership interest in our general partner. We sell product to and purchase product from SemGroup, and these transactions are included within revenues and cost of sales, respectively, in our consolidated statements of operations (certain of the purchases and sales that were entered into in contemplation of each other are recorded on a net basis within revenues in our consolidated statement of operations). We also lease crude oil storage from SemGroup. The following table summarizes transactions with SemGroup for the year ended March 31, 2016 (in thousands):

Sales to SemGroup	$109,557

Purchases from SemGroup 117,538

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WPX

Bryan K. Guderian is a member of our board of directors and an executive officer of WPX. We purchase crude oil from and sell crude oil to WPX (certain of the purchases and sales that were entered into in contemplation of each other are recorded on a net basis within revenues in our consolidated statement of operations). The following table summarizes transactions with WPX for the year ended March 31, 2016 (in thousands):

Sales to WPX	$ 101,052
Purchases from WPX	169,648

Other Transactions

We purchase goods and services from certain entities that are partially owned by our executive officers. The following table summarizes these transactions for the year ended March 31, 2016:

Entity	Nature of Purchases	Amount Purchased		Ownership Interest in Entity	
		(in thousands)			
Shawn W. Coady					
Hicks Motor Sales	Vehicle purchases	$	640	50	%
Vincent J. Osterman					
VE Properties III, LLC	Office space rental	153		100	%
H. Michael Krimbill					
Pinnacle Aviation 2007, LLC	Aircraft rental	81		50	%
H. Michael Krimbill					
KAIR2014 LLC	Aircraft rental	47		50	%

We provide goods and services to certain entities that are partially owned by our executive officers. The following table summarizes these transactions for the year ended March 31, 2016:

Entity	Nature of Services	Revenues Generated		Ownership Interest in Entity	
		(in thousands)			
James J. Burke					
Impact Energy Services, LLC	Truck transportation services	$	314	50	%

Todd M. Coady, an officer and employee of the Partnership, is the brother of Shawn W. Coady, who is an officer of the Partnership and a member of the board of directors. Todd M. Coady's annual base compensation is $250,000. Todd M. Coady reduced his hours in January 2016, and his annual base of compensation is $125,000. Todd M. Coady was also eligible to participate in the Partnership's 401(k) plan, and he received $5,889 of employer matching contributions during the year ended March 31, 2016. In April 2015, Todd M. Coady was granted 24,000 Performance Units that vested on July 1, 2015. The aggregate grant date fair value of these awards was $346,982. In July 2015, Todd M. Coady was granted a bonus of 6,666 restricted units that vested during August 2015. The grant date fair value of this bonus was $185,815. Todd M. Coady was also granted 8,000 Service Award units that are scheduled to vest on July 1, 2016. The aggregate grant date fair value of this award was $62,880.

Timothy Osterman, an employee of the Partnership, is the son of Vincent J. Osterman, who is an executive officer of the Partnership and a member of the board of directors. Timothy Osterman's base compensation during the year ended March 31, 2016 was $110,000. In July 2015, Timothy Osterman was granted a bonus of 6,069 restricted units that vested during August 2015. The grant date fair value of this bonus was $169,174. Timothy Osterman was also eligible to participate in the Partnership's 401(k) plan, and he received $3,850 of employer matching contributions during the year ended March 31, 2016. In March 2015, Timothy Osterman was granted 2,000 units of which 1,000 units vested on July 1, 2015 and the other 1,000 units will vest on July 1, 2016. The aggregate grant date fair value of this award was $45,220. Timothy Osterman was also granted 5,000 Service Award units in February 2016, that are scheduled to vest on July 1, 2016. The aggregate grant date fair value of this award was $39,300.

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Registration Rights Agreement

We have entered into a registration rights agreement (as amended, the "Registration Rights Agreement") with certain third parties (the "registration rights parties") pursuant to which we agreed to register for resale under the Securities Act of 1933, as amended ("Securities Act") common units, including any common units issued upon the conversion of subordinated units, owned by the parties to the Registration Rights Agreement. In connection with our IPO, we granted registration rights to the NGL Energy LP Investor Group, and subsequently, we have granted registration rights in connection with several acquisitions. We will not be required to register such common units if an exemption from the registration requirements of the Securities Act is available with respect to the number of common units desired to be sold. Subject to limitations specified in the Registration Rights Agreement, the registration rights of the registration rights parties include the following:

- Demand Registration Rights. Certain registration rights parties deemed "Significant Holders" under the agreement may, to the extent that they continue to own more than 4% of our common units, require us to file a registration statement with the SEC registering the offer and sale of a specified number of common units, subject to limitations on the number of requests for registration that can be made in any twelve-month period as well as customary cutbacks at the discretion of the underwriters relating to a potential offering. All other registration rights parties are entitled to notice of a Significant Holder's exercise of its demand registration rights and may include their common units in such registration. We can only be required to file a total of nine registration statements upon the Significant Holders' exercise of these demand registration rights and are only required to effect demand registration if the aggregate proposed offering price to the public is at least $10.0 million.
- Piggyback Registration Rights. If we propose to file a registration statement under the Securities Act to register our common units, the registration rights parties are entitled to notice of such registration and have the right to include their common units in the registration, subject to limitations that the underwriters relating to a potential offering may impose on the number of common units included in the registration. These counterparties also have the right to include their units in our future registrations, including secondary offerings of our common units.
- Expenses of Registration. With specified exceptions, we are required to pay all expenses incidental to any registration of common units, excluding underwriting discounts and commissions.

Review, Approval or Ratification of Transactions with Related Parties

The board of directors of our general partner has adopted a Code of Business Conduct and Ethics that, among other things, sets forth our policies for the review, approval and ratification of transactions with related persons. The Code of Business Conduct and Ethics provides that the board of directors of our general partner or its authorized committee will periodically review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the Code of Business Conduct and Ethics provides that our officers will make all reasonable efforts to cancel or annul the transaction.

The Code of Business Conduct and Ethics provides that, in determining whether or not to recommend the initial approval or ratification of a related party transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to:

- whether there is an appropriate business justification for the transaction;
- the benefits that accrue to the Partnership as a result of the transaction;
- the terms available to unrelated third parties entering into similar transactions;
- the impact of the transaction on a director's independence (in the event the related party is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer);

- the availability of other sources for comparable products or services;
- whether it is a single transaction or a series of ongoing, related transactions; and
- whether entering into the transaction would be consistent with the Code of Business Conduct and Ethics.

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Director Independence

The NYSE does not require a listed publicly traded partnership like us to have a majority of independent directors on the board of directors of our general partner. For a discussion of the independence of the board of directors of our general partner, please see Part III, Item 10–"Directors, Executive Officers and Corporate Governance–Board of Directors of our General Partner."

Item 14. Principal Accounting Fees and Services

We have engaged Grant Thornton LLP as our independent registered public accounting firm. The following table summarizes fees we have paid Grant Thornton LLP to audit our annual consolidated financial statements and for other services for the periods indicated:

	March 31,	
	2016	2015
Audit fees (1)	$2,676,038	$2,762,764
Audit-related fees	—	—
Tax fees (2)	—	30,000
All other fees	—	—
Total	$2,676,038	$2,792,764

(1) Includes fees for audits of the Partnership's financial statements, reviews of the related quarterly financial statements, and services that are normally provided by the independent accountants in connection with statutory and regulatory filings or engagements, including reviews of documents filed with the SEC and the preparation of letters to underwriters and other requesting parties.

(2) Includes fees for tax services in connection with tax compliance and consultation on tax matters.

Audit Committee Approval of Audit and Non-Audit Services

The audit committee of the board of directors of our general partner has adopted a pre-approval policy with respect to services which may be performed by Grant Thornton LLP. This policy lists specific audit-related services as well as any other services that Grant Thornton LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional audit committee authorization. The audit committee receives quarterly reports on the status of expenditures pursuant to the pre-approval policy. The audit committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the audit committee prior to engagement.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report:

1. Financial Statements. Please see the accompanying Index to Financial Statements.
2. Financial Statement Schedules. All schedules have been omitted because they are either not applicable, not required or the information required in such schedules appears in the financial statements or the related notes.
3. Exhibits.

Exhibit Number	Description
2.1	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, as the Representative, OWL Pearsall SWD, LLC, OWL Pearsall Holdings, LLC, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.2	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, as the Representative, OWL Karnes SWD, LLC, OWL Karnes Holdings, LLC, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.3	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, OWL Cotulla SWD, LLC, Terry Bailey, as trustee of the PJB Irrevocable Trust, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.4	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, OWL Nixon SWD, LLC, Terry Bailey, as trustee of the PJB Irrevocable Trust, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.4 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.5	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, HR OWL, LLC, OWL Operating, LLC, Lotus Oilfield Services, L.L.C., OWL Lotus, LLC, NGL Energy Partners, LP, High Sierra Water-Eagle Ford, LLC and High Sierra Transportation, LLC (incorporated by reference to Exhibit 2.5 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.6	Equity Interest Purchase Agreement, dated November 5, 2013, by and among NGL Energy Partners LP, High Sierra Energy, LP, Gavilon, LLC and Gavilon Energy Intermediate, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 5, 2013)
3.1	Certificate of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-172186) filed on April 15, 2011)
3.2	Certificate of Amendment to Certificate of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.2 to the Registration Statement on Form S-1 (File No. 333-172186) filed on April 15, 2011)
3.3	Second Amended and Restated Agreement of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed on May 17, 2011)
3.4	

First Amendment to Second Amended and Restated Agreement of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed on October 26, 2011)

3.5 Second Amendment to Second Amended and Restated Agreement of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed on January 9, 2012)

3.6 Third Amendment to Second Amended and Restated Agreement of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed on January 26, 2012)

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Exhibit Number	Description
3.7	Fourth Amendment to Second Amended and Restated Agreement of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 17, 2012)
3.8	Certificate of Formation of NGL Energy Holdings LLC (incorporated by reference to Exhibit 3.4 to the Registration Statement on Form S-1 (File No. 333-172186) filed on April 15, 2011)
3.9	Certificate of Amendment to Certificate of Formation of NGL Energy Holdings LLC (incorporated by reference to Exhibit 3.5 to the Registration Statement on Form S-1 (File No. 333-172186) filed on April 15, 2011)
3.10	Third Amended and Restated Limited Liability Company Agreement of NGL Energy Holdings LLC (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed on February 28, 2013)
3.11	Amendment No. 1 to Third Amended and Restated Limited Liability Company Agreement of NGL Energy Holdings LLC, dated as of August 6, 2013 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
3.12	Amendment No. 2 to Third Amended and Restated Limited Liability Company Agreement of NGL Energy Holdings LLC, dated as of June 27, 2014 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 3, 2014)
4.1	First Amended and Restated Registration Rights Agreement, dated October 3, 2011, by and among the Partnership, Hicks Oils & Hicksgas, Incorporated, NGL Holdings, Inc., Krim2010, LLC, Infrastructure Capital Management, LLC, Atkinson Investors, LLC, E. Osterman Propane, Inc. and the other holders party thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed on October 7, 2011)
4.2	Amendment No. 1 and Joinder to First Amended and Restated Registration Rights Agreement dated as of November 1, 2011 by and among the Partnership and SemStream (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed on November 4, 2011)
4.3	Amendment No. 2 and Joinder to First Amended and Restated Registration Rights Agreement, dated January 3, 2012, by and among NGL Energy Holdings LLC, Liberty Propane, L.L.C., Pacer-Enviro Propane, L.L.C., Pacer-Pittman Propane, L.L.C., Pacer-Portland Propane, L.L.C., Pacer Propane (Washington), L.L.C., Pacer-Salida Propane, L.L.C. and Pacer-Utah Propane, L.L.C. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed on January 9, 2012)
4.4	Amendment No. 3 and Joinder to First Amended and Restated Registration Rights Agreement, dated May 1, 2012, by and between NGL Energy Holdings LLC and Downeast Energy Corp. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on May 4, 2012)
4.5	Amendment No. 4 and Joinder to First Amended and Restated Registration Rights Agreement, dated June 19, 2012, by and between NGL Energy Holdings LLC and NGP M&R HS LP LLC (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 25, 2012)
4.6	Amendment No. 5 and Joinder to First Amended and Restated Registration Rights Agreement, dated October 1, 2012, by and between NGL Energy Holdings LLC and Enstone, LLC (incorporated by reference to Exhibit 4.1

	to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 3, 2012)
4.7	Amendment No. 6 and Joinder to First Amended and Restated Registration Rights Agreement, dated November 13, 2012, by and between NGL Energy Holdings LLC and Gerald L. Jensen, Thrift Opportunity Holdings, LP, Jenco Petroleum Corporation, Caritas Trust, Animosus Trust and Nitor Trust (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on November 19, 2012)
4.8	Amendment No. 7 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of August 1, 2013, by and among NGL Energy Holdings LLC, Oilfield Water Lines, LP and Terry G. Bailey (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
4.9	Amendment No. 8 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of February 17, 2015, by and among NGL Energy Holdings LLC and Magnum NGL Holdco LLC (incorporated by reference to Exhibit 4.9 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)

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Exhibit Number	Description
4.10*	Amendment No. 9 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of February 25, 2016, by and among NGL Energy Holdings LLC and Magnum NGL Holdco LLC
4.11	Note Purchase Agreement, dated June 19, 2012, by and among NGL and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 25, 2012)
4.12	Amendment No. 1 to Note Purchase Agreement, dated as of January 15, 2013, among the Partnership and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on January 18, 2013)
4.13	Amendment No. 2 to Note Purchase Agreement, dated as of May 8, 2013, among the Partnership and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed on May 9, 2013)
4.14	Amendment No. 3 to Note Purchase Agreement, dated September 30, 2013, among NGL Energy Partners LP and the holders of NGL's 6.65% senior secured notes due 2022 signatory thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 3, 2013)
4.15	Amendment No. 4 to Note Purchase Agreement, dated as of November 5, 2013, among the Partnership and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on November 8, 2013)
4.16	Amendment No. 5 to Note Purchase Agreement, dated as of December 23, 2013, among the Partnership and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 30, 2013)
4.17	Amendment No. 6 to Note Purchase Agreement, dated as of June 30, 2014, among the Partnership and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 3, 2014)
4.18	Amendment No. 7 to Note Purchase Agreement, dated as of December 19, 2014 and effective as of December 26, 2014, among the Partnership and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed on January 2, 2015)
4.19	Amendment No. 8 to Note Purchase Agreement, dated as of May 1, 2015, among the Partnership and the purchasers named therein (incorporated by reference to Exhibit 4.18 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.20	Amendment No. 9 to Note Purchase Agreement, dated as of December 23, 2015, among the Partnership and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2015 filed with the SEC on February 9, 2016)
4.21*	Amendment No. 10 to Note Purchase Agreement, dated as of February 9, 2016, among the Partnership and the purchasers named therein
4.22	Indenture, dated as of October 16, 2013, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to

	Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 16, 2013)
4.23	Forms of 6.875% Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 16, 2013)
4.24	First Supplemental Indenture, dated as of December 2, 2013, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.19 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2014 filed with the SEC on May 30, 2014)
4.25	Second Supplemental Indenture, dated as of April 22, 2014, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiary party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.20 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2014 filed with the SEC on May 30, 2014)
4.26	Third Supplemental Indenture, dated as of July 31, 2014, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiary party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.6 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended September 30, 2014 filed with the SEC on November 10, 2014)

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Exhibit Number	Description
4.27	Fourth Supplemental Indenture, dated as of December 1, 2014, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.25 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.28	Fifth Supplemental Indenture, dated as of February 17, 2015, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.26 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.29	Sixth Supplemental Indenture, dated as of August 21, 2015, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended September 30, 2015 filed with the SEC on November 9, 2015)
4.30	Registration Rights Agreement, dated as of October 16, 2013, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the Guarantors listed therein on Exhibit A and RBC Capital Markets, LLC as representative of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 16, 2013)
4.31	Registration Rights Agreement, dated December 2, 2013, by and among NGL Energy Partners LP and the purchasers set forth on Schedule A thereto (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 5, 2013)
4.32	Indenture, dated as of July 9, 2014, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 9, 2014)
4.33	Forms of 5.125% Senior Notes due 2019 (incorporated by reference and included as Exhibits A1 and A2 to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 9, 2014)
4.34	Registration Rights Agreement, dated July 9, 2014, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the Guarantors listed therein on Exhibit A and RBS Securities Inc. as representative of the several initial purchasers (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 9, 2014)
4.35	First Supplemental Indenture, dated as of July 31, 2014, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.5 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended September 30, 2014 filed with the SEC on November 10, 2014)
4.36	Second Supplemental Indenture, dated as of December 1, 2014, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.32 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.37	Third Supplemental Indenture, dated as of February 17, 2015, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National

	Association, as Trustee (incorporated by reference to Exhibit 4.33 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.38	Fourth Supplemental Indenture, dated as of August 21, 2015, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended September 30, 2015 filed with the SEC on November 9, 2015)
10.1	Credit Agreement, dated as of June 19, 2012, among NGL Energy Partners LP, the NGL subsidiary borrowers, the lenders party thereto and Deutsche Bank Trust Company Americas, as administrative agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 25, 2012)
10.2	Facility Increase Agreement, dated as of November 1, 2012, among NGL Energy Operating LLC, NGL Energy Partners LP, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on November 7, 2012)

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Exhibit Number	Description
10.3	Amendment No. 1 to Credit Agreement, dated as of January 15, 2013, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on January 18, 2013)
10.4	Amendment No. 2 to Credit Agreement, dated as of May 8, 2013, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No 001-35172) filed on May 9, 2013)
10.5	Amendment No. 3 to Credit Agreement, dated September 30, 2013, among NGL Energy Partners LP, NGL Energy Operating LLC, each subsidiary of NGL identified as a "Borrower" therein, Deutsche Bank AG, New York Branch, as technical agent, Deutsche Bank Trust Company Americas, as administrative agent and collateral agent and each financial institution identified as a "Lender" or "Issuing Bank" therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 3, 2013)
10.6	Amendment No. 4 to Credit Agreement, dated as of November 5, 2013, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on November 8, 2013)
10.7	Amendment No. 5 to Credit Agreement, dated as of December 23, 2013, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank and Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 30, 2013)
10.8	Facility Increase Agreement, dated as of December 30, 2013, among NGL Energy Operating LLC, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on January 3, 2014)
10.9	Amendment No. 6 to Credit Agreement, dated as of June 12, 2014, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 16, 2014)
10.10	Amendment No. 7 to Credit Agreement, dated as of June 27, 2014, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on July 3, 2014)
10.11	Facility Increase Agreement, dated December 1, 2014, among NGL Energy Operating LLC, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 1, 2014)
10.12	Amendment No. 8 to Credit Agreement, dated as of December 19, 2014 and effective as of December 26, 2014, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to

	Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed on January 2, 2015)
10.13	Amendment No. 9 to Credit Agreement, dated as of May 1, 2015, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
10.14	Amendment No. 10 to Credit Agreement, dated as of July 31, 2015, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 4, 2015)
10.15	Facility Increase Agreement, dated October 7, 2015, among NGL Energy Operating LLC, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2015 filed with the SEC on February 9, 2016)

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Exhibit Number	Description
10.16	Amendment No. 11 to Credit Agreement, dated as of December 23, 2015, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2015 filed with the SEC on February 9, 2016)
10.17*	Amendment No. 12 to Credit Agreement, dated as of February 9, 2016, among NGL Energy Operating LLC, the Partnership, the subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas and the other financial institutions party thereto
10.18	Common Unit Purchase Agreement, dated November 5, 2013, by and among NGL Energy Partners LP and the purchasers listed on Schedule A thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 5, 2013)
10.19+	Letter Agreement among Silverthorne Energy Holdings LLC, Shawn W. Coady and Todd M. Coady dated October 14, 2010 (incorporated by reference to Exhibit 10.11 to the Registration Statement on Form S-1 (File No. 333-172186) filed on April 15, 2011)
10.20+	NGL Energy Partners LP 2011 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed on May 17, 2011)
10.21+	Form of Restricted Unit Award Agreement under the NGL Energy Partners LP 2011 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended June 30, 2012 filed with the SEC on August 14, 2012)
10.22	NGL Performance Unit Program (incorporated by reference to Exhibit 10.18 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
12.1*	Computation of ratios of earnings to fixed charges
21.1*	List of Subsidiaries of NGL Energy Partners LP
23.1*	Consent of Grant Thornton LLP
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS**	XBRL Instance Document
101.SCH**	XBRL Schema Document

101.CAL** XBRL Calculation Linkbase Document

101.DEF** XBRL Definition Linkbase Document

101.LAB** XBRL Label Linkbase Document

101.PRE** XBRL Presentation Linkbase Document

* Exhibits filed with this report.

** The following documents are formatted in XBRL (Extensible Business Reporting Language): (i) Consolidated Balance Sheets at March 31, 2016 and 2015, (ii) Consolidated Statements of Operations for the years ended March 31, 2016, 2015, and 2014, (iii) Consolidated Statements of Comprehensive Income (Loss) for the years ended March 31, 2016, 2015, and 2014, (iv) Consolidated Statements of Changes in Equity for the years ended March 31, 2016, 2015, and 2014, (v) Consolidated Statements of Cash Flows for the years ended March 31, 2016, 2015, and 2014, and (vi) Notes to Consolidated Financial Statements.

+ Management contracts or compensatory plans or arrangements.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on May 31, 2016.

NGL ENERGY PARTNERS LP

By: NGL Energy Holdings LLC, its general partner

By: /s/ H. Michael Krimbill
H. Michael Krimbill
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this 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/ H. Michael Krimbill H. Michael Krimbill	Chief Executive Officer and Director (Principal Executive Officer)	May 31, 2016
/s/ Robert W. Karlovich III Robert W. Karlovich III	Chief Financial Officer (Principal Financial Officer)	May 31, 2016