UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended March 31, 2015

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

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 x 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 (Section 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 x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 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 x

The aggregate market value at September 30, 2014 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 ($39.37 per Common Unit) was $3,078,563,331. 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 25, 2015, there were 106,328,594 common units issued and outstanding.

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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. When used in this Annual Report, words such as anticipate, believe, could, estimate, expect, forecast, goal, intend, may, plan, project, will, and similar expressions and s plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our general partner believe that the expectations on which such forward-looking statements are based are reasonable, neither we nor our general partner can give assurances that such expectations 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 anticipated, estimated, projected or expected. Among the key risk factors that may impact our consolidated financial position and results of operations are:

- the prices for crude oil, natural gas, natural gas liquids, refined products, ethanol, and biodiesel;
- energy prices generally;
- the price of propane and distillates relative to the price of alternative and competing fuels;
- the price of gasoline relative to the price of corn, which impacts the price of ethanol;
- 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 in which we have water treatment and disposal facilities;

- the ability to obtain adequate supplies of propane and distillates for retail sale in the event of an interruption in supply or transportation and the availability of capacity to transport propane and distillates to market areas;

- actions taken by foreign oil and gas producing nations;

- the political and economic stability of petroleum 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;

- availability of local, intrastate and interstate transportation infrastructure, including with respect to our truck, railcar, and barge transportation services;

- availability, price, and marketing of competitive 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 and on the treatment of flowback and produced water;

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- hazards or operating risks incidental to the transporting and distributing of petroleum products that may not be fully covered by insurance;
- the maturity of the crude oil and natural gas liquids industries and competition from other marketers;
- loss of key personnel;
- the ability to hire drivers;
- the ability to renew contracts with key customers;
- the ability to maintain or increase the margins we realize for our terminal, barging, trucking and water disposal, and recycling, and discharge services;
- the ability to renew leases for our leased equipment and storage facilities;
- the nonpayment or nonperformance by our customers;
- 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 crude oil 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 laws and regulations to which we are subject, 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 Fuels Standard;

- the operational and financial success of our joint ventures; 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 to 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 39 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, 2015. Unless otherwise indicated, this data is as of March 31, 2015.

Item 1. Business

Overview

We are a Delaware limited partnership formed in September 2010. Subsequent to our formation, we significantly expanded our operations through numerous business combinations. At March 31, 2015, our operations include:

- Our crude oil logistics segment, the assets of which include owned and leased crude oil storage terminals, owned and leased pipeline injection stations, a fleet of owned trucks and trailers, a fleet of owned and leased railcars, a fleet of owned and leased barges and towboats, and a 50% interest in a crude oil pipeline. Our crude oil logistics segment purchases crude oil from producers and transports it 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 treatment and disposal facilities. Our water solutions segment generates revenues from the treatment and disposal of wastewater generated from crude oil and natural gas production, from the sale of recycled water and recovered hydrocarbons, and from the disposal of solids such as tank bottoms and drilling fluids.

- 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 services through its 21 owned terminals throughout the United States and railcar transportation services through its fleet of leased railcars. Our liquids segment purchases propane, butane, and other products from refiners, processing plants, producers, and other parties, and sells the products to retailers, refiners, petrochemical plants, and other participants in the wholesale markets.

- 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 also own the 2.0% general partner interest and a 19.6% limited partner interest in TransMontaigne Partners L.P. (TLP), which conducts refined products terminaling operations. TLP also owns a 42.5% interest in Battleground Oil Specialty Terminal Company LLC (BOSTCO) and a 50% interest in Frontera Brownsville LLC (Frontera), which are entities that own refined products storage facilities.

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 initial public offering (IPO) in May 2011, we significantly expanded our operations through numerous acquisitions, including the following, among others:

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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.

- 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 provides us the right to purchase water treatment and disposal facilities developed by the other party to the agreement, and we are also party to a solids facilities development agreement with this other party. During March 2014, we purchased one additional facility under this development agreement. During the year ended March 31, 2015, we purchased 16 water treatment and disposal facilities 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

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(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

- 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 2.0% general partner interest, the incentive distribution rights, a 19.7% limited partner interest in TLP, and assumed certain terminaling service agreements with TLP from an affiliate of the previous owner of TransMontaigne.

- In November 2014, we completed the acquisition of 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 U.S. markets and entered into a construction agreement to expand the storage capacity of the facility.

Primary Service Areas

The following maps show the primary service areas of our businesses at various points in time, to illustrate the growth of our businesses:

Primary Service Areas at March 31, 2012

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Primary Service Areas at March 31, 2013

Primary Service Areas at March 31, 2014

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Primary Service Areas at March 31, 2015

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Organizational Chart

The following chart provides a summarized view of our legal entity structure at March 31, 2015:

(1) Includes the operations of our crude oil logistics, refined products, and renewables businesses.

(2) Includes the operations of our water solutions business.

(3) Includes the operations of our liquids business.

(4) Includes the operations of our retail propane business.

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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 producers.* 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 have acquired. We also believe that there are further organic growth opportunities within our existing businesses, particularly within our crude oil logistics, water solutions, and refined products businesses.

- *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 crude oil logistics platform, and enhance our geographic diversity in our water solutions business. 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*. In our liquids, crude oil logistics, and refined products businesses, we intend to focus on long-term contracts associated with pipelines in addition to back-to-back contracts which minimize commodity price exposure. In our water solutions business, cash flows are supported by certain fee-based, multi-year contracts, some of which include acreage dedications from producers or volume commitments. We believe that expanding our retail propane business with an emphasis on a high level of residential customers and a high level of company-owned tanks will result in strong customer retention rates and consistent operating margins. Our refined products business is backed by term marketing agreements and long-term throughput agreements for terminaling operations.

- *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 maintain sufficient liquidity to manage existing and future capital requirements.

- *Maintain a disciplined cash distribution policy that complements our 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. 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 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 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 producers in numerous geographic areas enhances our competitive position. 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.

• *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 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 Businesses

Crude Oil Logistics

Overview. Our crude oil logistics segment purchases crude oil from producers and transports it for resale at owned and leased pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs. 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 approximately 275,000 barrels per day of crude oil using the following assets:

- 300 owned trucks and 300 owned trailers operating primarily in the Mid-Continent, Permian Basin, Eagle Ford shale play, and Rocky Mountain regions;

- 400 owned railcars and 350 leased railcars operating primarily in Colorado, New Mexico, North Dakota, Oklahoma, Wyoming, and West Texas; and

- 8 owned towboats, 19 owned barges, 2 leased towboats and 6 leased 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 350 leased railcars, 100 are compliant with these standards.

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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 44 pipeline injection stations. The location of these facilities is summarized below.

State	Number of Pipeline Injection Stations
Oklahoma	17
Texas	15
New Mexico	5
Kansas	3
North Dakota	3
Montana	1
Total	44

We also lease 5 pipeline injection stations in Kansas, Montana, and North Dakota. We own and lease several rail transload facilities and have several throughput agreements at rail transload facilities in Colorado, New Mexico, North Dakota, and Oklahoma. 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 4,140,000 barrels, 1,000,000 barrels of which are owned by Glass Mountain. The combined storage capacity of the other six terminals is 462,500 barrels.

We lease 3,703,000 barrels of capacity at three storage terminal facilities. Of this leased storage capacity, 3,350,000 barrels are at Cushing, Oklahoma.

We have one Gulf Coast terminal facility that is under construction and is expected to be completed early in fiscal year 2017 with a total expected storage capacity of 300,000 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. We also own Grand Mesa, which is constructing a 20-inch crude oil pipeline originating in Weld County, Colorado and terminating at our Cushing, Oklahoma terminal. We anticipate that the pipeline will commence service in the second half of calendar year 2016. Upon completion, Grand Mesa is expected to have a capacity in excess of 200,000 barrels per day. Rimrock Midstream LLC s Platte River gathering system, which is currently under development, is expected to deliver volumes from multiple shippers to Grand Mesa s northern origin near Lucerne, Colorado.

Customers. Our customers include crude oil refiners, producers, and marketers. During the year ended March 31, 2015, 65% of the revenues of the 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;
- reliability of service;
- logistics capabilities, including the availability of railcars, proprietary terminals, and owned pipelines, barges, railcars, trucks, and towboats;

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- 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 600 producers at 6,200 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 the forward crude price is greater than the spot price) and can be backwardated (a condition in which the forward crude price is lower than the spot price). 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 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 generates revenues from the treatment and disposal of wastewater generated from crude oil and natural gas production, from the sale of recycled water and recovered hydrocarbons, and from the disposal of solids such as tank bottoms and drilling fluids. Our facilities are 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 three months ended March 31, 2015, we took delivery of 48.9 million barrels of wastewater, an average of 543,000 barrels per day.

Our water solutions segment is in the process of expanding its 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 will be 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.

Operations. We own 46 water treatment and disposal facilities, including 58 wells. The location of the facilities and the processing capacities at which the facilities currently operate are summarized below.

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Location	Processing Capacity (barrels per day)	Located on Land We Own or Lease
Pinedale Anticline:		
Pinedale, Wyoming (A)	60,000	Lease
DJ Basin:		
Briggsdale, Colorado (B)	34,000	Own
Grover, Colorado	25,000	Own
Greeley, Colorado	18,000	Lease
Grover, Colorado	17,500	Lease
Platteville, Colorado (B)	16,200	Own
Kersey, Colorado	14,000	Own
Orchard, Colorado	10,000	Own
LaSalle, Colorado	5,900	Own
Brighton, Colorado	5,100	Own
Total DJ Basin	145,700	
Permian Basin:		
Mentone, Texas	35,000	Own
Orla, Texas (C)	35,000	Own
Big Lake, Texas	30,000	Own
Orla, Texas	30,000	Own
Big Spring, Texas	25,000	Own
Garden City, Texas	25,000	Own
Kermit, Texas	25,000	Own
Rankin, Texas	25,000	Own
Pecos, Texas	23,000	Own
Colorado City, Texas	20,000	Own
Crane, Texas	20,000	Own
Midland, Texas	20,000	Own
Midkiff, Texas	18,000	Own
Barnhart, Texas	16,000	Own
Andrews, Texas	12,000	Own
Total Permian Basin	359,000	
Eagle Ford Shale Play:		
Carrizo Springs, Texas (D)	22,500	Lease
Catarina, Texas (D)	22,000	Lease
Charlotte, Texas	22,000	Own
Cheapside, Texas	22,000	Own
Gillett, Texas	22,000	Own
Karnes City, Texas	22,000	Own
Artesia Wells, Texas	20,000	Own
Los Angeles, Texas	20,000	Lease
Nixon, Texas	20,000	Own
Tilden, Texas	20,000	Lease
Westhoff, Texas (C)	20,000	Own
Fowlerton, Texas	18,000	Own
Pearsall, Texas	17,000	Lease
Cotulla, Texas	16,500	Own
Dilley Lea, Texas	15,000	Lease
Catarina, Texas (D)	12,000	Lease
Total Eagle Ford Shale Play	311,000	
Eaglebine Shale Play:		
Madisonville, Texas	20,000	Own
Granite Wash Shale Play:		
Wheeler, Texas	27,000	Own
Canadian, Texas	25,000	Own
Total Granite Wash Shale Play	52,000	

Bakken Shale Play:		
Killdeer, North Dakota	20,000	Lease
Johnsons Corner, North Dakota	20,000	Own
Total Bakken Shale Play	40,000	
Total All Facilities	987,700	

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(A) 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.

(B) The processing capacity listed above for each of these facilities includes a design capacity of 10,000 barrels per day to process water to a recycle standard.

(C) These 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.

(D) Reflects the total processing capacity of each facility, of which we own a 75% interest in each of these facilities.

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 with trucks.

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. We have recycled approximately 9 million barrels (378 million gallons) of recycle quality water since our merger with High Sierra in June 2012. We have returned approximately 5 million barrels (210 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.

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 customers of our facility in Wyoming have committed to deliver a specified minimum volume of water to our facility under long-term contracts. The primary customers of our facilities in Colorado have committed to deliver to our facilities all wastewater produced at all wells in a designated area. One customer in Texas has committed to deliver at least 50,000 barrels of wastewater per day to our facilities. Most of the customers at our other facilities are not under volume commitments. During the year ended March 31, 2015, 23% of the water treatment and disposal revenues of the water solutions segment were generated from our two largest customers of the segment, and 57% 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 significant crude oil and natural gas production.

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 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, 2015, we sold 2.1 billion gallons of natural gas liquids, an average of 5.75 million gallons per day.

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 21 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 chart lists 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. Catherines, Ontario, Canada	700,000
Janesville, Wisconsin	553,000
Light, Arkansas	524,400
Rixie, Arkansas	524,400
Winslow, Arizona	500,000
West Springfield, Massachusetts	441,000
Albuquerque, New Mexico	408,000
Kingsland, Arkansas	405,000
Portland, Maine	360,000
Vancouver, Washington	358,000
Green Bay, Wisconsin	310,000
Thackerville, Oklahoma	235,000
Ritzville, Washington	198,000
Sidney, Montana	180,000
Shelton, Washington	161,000
Total	12,110,800

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

In February 2015 we acquired an underground storage facility near Delta, Utah. This facility currently has capacity to store approximately 1.8 million barrels of natural gas liquids. We have begun construction of new caverns to expand the storage capacity, and we expect these new caverns to be operational during the year ending March 31, 2016. We lease storage to 11 customers, with lease terms ranging from one to four years. The facility is located on property for which we have a long-term lease.

We lease 4,591 railcars, of which 520 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.

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, Michigan, Mississippi, Missouri, and Texas.

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The following chart shows our leased storage space at natural gas liquids storage facilities and interconnects to those facilities:

	Leased Storage Space (gallons)		
Storage Facility	Beginning April 1, 2015	At March 31, 2015	Storage Interconnects
Conway, Kansas	64,940,000	73,290,000	Connected to Enterprise Mid-America and NuStar Pipelines; Rail Facility
Borger, Texas	42,000,000	42,000,000	Connected to ConocoPhillips Blue Line Pipeline
Bushton, Kansas	12,600,000	10,500,000	Connected to ONEOK North System Pipeline
Mont Belvieu, Texas	3,150,000	3,150,000	Connected to Enterprise Texas Eastern Products Pipeline
Carthage, Missouri	7,560,000	7,560,000	Connected to Mid-America Pipeline
Marysville, Michigan	2,100,000	4,200,000	Connected to Cochin Pipeline
Hattiesburg, Mississippi	11,340,000	6,930,000	Connected to Enterprise Dixie Pipeline; Rail Facility
Redwater, Alberta, Canada	9,072,000	7,938,000	Connected to Cochin Pipeline; Rail Facility
Regina, Saskatchewan, Canada		1,260,000	Connected to Cochin Pipeline; Rail Facility
St. Clair, Michigan	6,300,000		Rail Facility
Adamana, Arizona	1,680,000	1,398,600	Rail Facility
Corunna, Ontario, Canada	2,100,000	2,100,000	Rail Facility
Total	162,842,000	160,326,600	

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 47 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 pipeline systems, rail terminals, refineries, and major United States propane storage hubs. During the year ended March 31, 2015, 33% of the revenues of the 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;
- logistics capabilities, including the availability of railcars, and proprietary terminals;

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- long-term customer relationships; and
- the acquisition of businesses.

Pricing Policy. In our natural gas 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 to as much as 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 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, 2015, we sold 204.1 million gallons of propane and distillates, an average of 559,000 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 107 customer service locations and 91 satellite distribution locations, with aggregate propane storage capacity of 11.5 million gallons and aggregate distillate storage capacity of 3.7 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 16,000 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 shows 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	21
Maine	16	10
Georgia	14	3
Massachusetts	10	8
North Carolina	8	1
Pennsylvania	7	3
Kansas	6	26
Indiana	4	5
Connecticut	4	2
South Carolina	3	
New Hampshire	2	1
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	
New Jersey		1
Vermont		1
Total	107	91

We own 82 of our 107 customer service centers and 63 of our 91 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, 2015, 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, 2015, we owned a fleet of 430 bulk delivery trucks, 40 semi-tractors, 40 propane transport trailers and 490 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 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 our customer service locations, and

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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 69% 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, 2015, 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, 2015.

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, fuel oil, 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

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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.

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. We own the 2.0% general partner interest and a 19.6% limited partner interest in TLP, which conducts refined products terminaling operations. TLP also owns a 42.5% interest in BOSTCO and a 50% interest in Frontera, which are entities that own refined products storage facilities. During the nine months ended March 31, 2015, we sold 60.1 million barrels of refined products, an average of 220,000 barrels per day.

Operations. We provide integrated terminal, transportation, storage, supply, distribution, and marketing services to refiners, wholesalers, distributors, marketers, and industrial and commercial end users of refined petroleum products. Although the assets and operations of TLP are included in our consolidated financial statements, this description of our business describes the activities of TLP separately.

The refined products we handle include gasoline, diesel fuel, heating oil, jet fuel, and kerosene. We purchase refined petroleum products primarily in the Gulf Coast, East Coast, 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.

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. We have the contractual right to the exclusive use of the majority of the terminals in TLP s Southeast region.

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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 approximately 60,000 barrels of biodiesel storage in Deer Park, Texas and have a terminaling agreement at a biodiesel facility in Phoenix, Arizona with a minimum monthly throughput requirement. We lease 32 railcars for the transportation of renewables.

Customers. Our refined products and renewables segment serves customers in 43 states. During the year ended March 31, 2015, 22% of the revenues of this segment were generated from the ten largest customers. 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 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.

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.

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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 contracted on a back-to-back basis where physical purchases are matched with physical sales. 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 2014 the federal government passed a law to reinstate the tax credit retroactively to January 1, 2014, with the credit expiring on December 31, 2014. Changes in future 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 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.

TLP

Overview. We own the 2.0% general partner interest and a 19.6% limited partner interest in TLP, which conducts refined products terminaling operations. TLP also provides storage of crude oil, fertilizer, chemicals, vegetable oils, naphtha, and wax.

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Operations. TLP is a terminaling and transportation company with operations in the United States. TLP uses its terminaling facilities to, among other things:

- receive refined products from the pipeline, ship, barge or railcar and transfer those refined products to the tanks located at its terminals;
- store the refined products in our tanks for its customers;
- monitor the volume of the refined products stored in its tanks;
- distribute the refined products out of our terminals in vessels, railcars or truckloads using truck racks and other distribution equipment located at its terminals, including pipelines; and
- heat residual fuel oils and asphalt stored in our tanks, and provide other ancillary services related to the throughput process.

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The locations and approximate aggregate active storage capacity at TLP s terminal facilities at March 31, 2015 were as follows:

Locations	Active Storage Capacity (shell barrels)
Gulf Coast Facilities	
Florida	
Cape Canaveral	724,000
Fisher Island	673,000
Jacksonville	271,000
Pensacola	270,000
Port Everglades Complex	
Port Everglades North	2,408,000
Port Everglades South	376,000
Port Manatee	1,375,000
Tampa	760,000
Gulf Coast Total	6,857,000
Midwest Facilities	
Cushing, Oklahoma	1,005,000
Oklahoma City, Oklahoma	158,000
Rogers, Arkansas and Mount Vernon, Missouri (aggregate amounts)	406,000
Midwest Total	1,569,000
Brownsville Facilities	
Brownsville, Texas	919,000
Frontera (1)	1,498,000
Brownsville Total	2,417,000
River Facilities	
Arkansas City, Arkansas	446,000
Baton Rouge, Louisiana (Dock)	
Cape Girardeau, Missouri	140,000
East Liverpool, Ohio	227,000
Evansville, Indiana	245,000
Greater Cincinnati, Kentucky	189,000
Greenville, Mississippi (Clay Street)	350,000
Greenville, Mississippi (Industrial Road)	56,000
Henderson, Kentucky	169,000
Louisville, Kentucky	183,000
New Albany, Indiana	201,000
Owensboro, Kentucky	157,000
Paducah, Kentucky	322,000
River Total	2,685,000
Southeast Facilities	
Albany, Georgia	203,000
Americus, Georgia	93,000
Athens, Georgia	203,000
Bainbridge, Georgia	367,000
Belton, South Carolina	
Birmingham, Alabama	178,000
Charlotte, North Carolina	121,000
Collins, Mississippi	200,000
Collins/Purvis, Mississippi	3,419,000
Doraville, Georgia	438,000
Fairfax, Virginia	513,000
Greensboro, North Carolina	479,000

Griffin, Georgia	107,000
Lookout Mountain, Georgia	219,000
Macon, Georgia	174,000
Meridian, Mississippi	139,000
Montvale, Virginia	503,000
Norfolk, Virginia	1,336,000
Richmond, Virginia	478,000
Rome, Georgia	152,000
Selma, North Carolina	529,000
Spartanburg, South Carolina	166,000
Southeast Total	10,017,000
BOSTCO (2)	7,080,000
Total Capacity	30,625,000

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(1) Reflects the total active storage capacity of Frontera, of which TLP has a 50% ownership interest.

(2) Reflects the completed construction total active storage capacity of BOSTCO, of which TLP has a 42.5%, general voting, Class A Member ownership interest.

TLP leases all or part of the land on which seven of the terminals are located. TLP owns the land on which its other terminals are located.

TLP owns and operates the Razorback pipeline. The Razorback pipeline is a 67-mile, 8-inch diameter interstate common carrier pipeline that transports light refined product from its terminal at Mount Vernon, Missouri where it is interconnected with a pipeline system owned by Magellan Midstream Partners, L.P., to TLP s terminal at Rogers, Arkansas. TLP also owns and operates the Diamondback pipeline. The Diamondback pipeline consists of an 8-inch pipeline that transports LPG approximately 16 miles from TLP s Brownsville, Texas facilities to the U.S./Mexico border and a 6-inch pipeline, which runs parallel to the 8-inch pipeline, that can be used by TLP in the future to transport additional LPG or refined products to Matamoros, Mexico. The 8-inch pipeline has a capacity of approximately 20,000 barrels per day. The 6-inch pipeline has a capacity of approximately 12,000 barrels per day. TLP also operates and maintains the United States portion of a 174-mile bidirectional refined products pipeline owned by P.M.I. Services North America Inc. This pipeline connects TLP s Brownsville, Texas terminal complex to a pipeline in Mexico that delivers to Petróleos Mexicanos (PEMEX) terminal located in Reynosa, Mexico and terminates at PEMEX s refinery, located in Cadereyta, Nuevo Leon, Mexico, a suburb of the large industrial city of Monterrey, Mexico.

Customers. TLP has several significant customer relationships from which it expects to derive a substantial majority of its revenue for the foreseeable future. During the period from July 1, 2014 through March 31, 2015, 33% of TLP s revenues were generated from services to NGL (these revenues are eliminated in our consolidated statements of operations).

Competition. TLP faces competition from other terminals and pipelines that may be able to supply customers with integrated terminaling and transportation services on a more competitive basis. TLP competes with national, regional and local terminal and transportation companies, including the major integrated oil companies, of widely varying sizes, financial resources and experience. TLP s ability to compete could be harmed by factors we cannot control, including:

- price competition from terminal and transportation companies, some of which are substantially larger than we are and have greater financial resources, and control substantially greater storage capacity, than TLP does;

- the perception that another company can provide better service; and

- the availability of alternative supply points, or supply points located closer to customers operations.

Supply. The volume of product that is handled, transported, throughput or stored in TLP s terminals and pipeline is directly affected by the level of supply and demand in the wholesale markets served by our terminals and pipelines. Overall supply of refined products in the wholesale markets is influenced by the products absolute prices, the availability of capacity on delivering pipelines and vessels, fluctuating refinery margins and the markets perception of future project prices.

Pricing Policy. TLP derives revenue from its terminal and pipeline transportation operations by charging fees for providing integrated terminaling, transportation and related services. The fees and other sources of revenue are composed of:

- ***Terminaling Service Fees.*** TLP generates terminaling service fees by receiving, storing and distributing products for customers. Terminaling service fees include throughput fees based on the volume of product distributed from the facility, injection fees based on the volume of product injected with additive compounds and storage fees based on a rate per barrel of storage capacity per month.

- ***Pipeline Transportation Fees.*** TLP earns pipeline transportation fees on its Razorback pipeline and Diamondback pipeline and the Ella-Brownsville pipeline, which it leases from a third party, based on the volume of product transported and the distance from the origin point to the delivery point. The Federal Energy Regulatory Commission (FERC) regulates the tariff on the Razorback, Diamondback and Ella-Brownsville pipelines.

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- ***Management Fees and Reimbursed Costs.*** TLP manages and operates certain tank capacity at its Port Everglades (South) terminal for a major oil company and receives a reimbursement of its proportionate share of operating and maintenance costs. TLP manages and operates for an affiliate of PEMEX, Mexico s state-owned petroleum company, a bidirectional products pipeline connected to its Brownsville, Texas terminal facility and receives a management fee and reimbursement of costs. TLP manages and operates Frontera and receives a management fee based on costs incurred.

- ***Other Revenue.*** TLP provides ancillary services including heating and mixing of stored products, product transfer services, railcar handling, wharfage fees and vapor recovery fees. Pursuant to certain terminaling services agreements with throughput customers, TLP is entitled to the volume of net product gained resulting from differences in the measurement of product volumes received and distributed at its terminaling facilities. Consistent with recognized industry practices, measurement differentials occur as the result of the inherent variances in measurement devices and methodology. TLP recognizes as revenue the net proceeds from the sale of the product gained.

Employees

At March 31, 2015, we had 3,100 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 oil are subject to FERC regulation including reporting or other requirements. In addition, the intrastate transportation and storage of 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 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

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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 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

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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 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 operations or financial condition.

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 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 operations or financial condition. 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 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.

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

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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 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 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 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 Supreme Court of the United States invalidated the Tailoring Rule in *Utility Air Regulatory Group v. EPA* on

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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 doing 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 a set of 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.

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

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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

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

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- 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.

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

Our ability to consummate 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.

Our ability to expand our retail propane business is dependent on our ability to successfully complete accretive acquisitions. 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. While our business strategy includes expanding

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our existing retail propane operations through internal growth, our ability to grow within the retail propane business will depend principally on acquisitions, and there can be no assurances that we will be able to identify suitable acquisition candidates or successfully complete acquisitions in this line of business.

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 financial condition, 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, financial condition 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 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 financial condition or results of operations.

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

At March 31, 2015, we had $2.7 billion of outstanding indebtedness. 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

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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 condition, 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 Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity, Sources of Capital and Capital Resource Activities Long-Term Debt.

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.

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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 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 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 oil and natural gas, the availability of liquids-rich natural gas needed to produce natural gas liquids, the supply of and demand for oil and natural gas, environmental restrictions on the exploration and production of oil and natural gas, such as existing and proposed regulation of hydraulic fracturing, domestic and worldwide economic conditions, political instability in 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 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 oil and natural gas prices, to the extent existing production is not replaced.

The oil and natural gas production industry tends to run in cycles and may, at any time, cycle into a downturn; if that occurs again, 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 oil and natural gas have caused many customers to reduce capital budgets for future periods and have caused decreased demand for 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 operating results.

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

Crude oil spot and forward prices experienced a significant decline during the second half of calendar year 2014, and this has 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 significant portion of the revenues of our water solutions business are generated from the sale of crude oil that we recover in the process of treating the 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

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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.

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 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 cars are transported. Any disruptions in the operations of these railroads could adversely impact our ability to deliver product to our customers.

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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 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 *Certain of our operations are subject to the jurisdiction of the FERC, and some of our operations could become 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, results of operations and financial condition.

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. This state regulation can have a material and adverse effect on that portion of our business, results of operations and financial condition.

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, results of operations, financial condition 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 oil and 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 wastewater treatment 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. In response to train derailments, United States regulators are implementing or considering new rules to address the safety risks of transporting crude oil by rail. 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 unfavorably 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 frac 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 operations and financial performance.

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

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become more stringent over time. For example, in April 2012, the EPA issued final rules that established new air emission controls for oil and 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. In January 2015, the EPA announced its intention to propose regulations that would require further reductions in methane and VOC emissions from the oil and gas industry. The EPA s schedule for proposing or finalizing these regulations is not presently known. 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 oil and 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 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 unfavorably impact the oil and gas drilling industry. For instance, the EPA has asserted federal regulatory 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. The EPA has also commenced a study of the potential environmental impact of hydraulic fracturing activities, the final results of which are expected in 2015. 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. The rule will become effective 90 days after publication in the Federal Register. 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 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 unfavorably 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.

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Seasonal weather conditions and natural or man-made disasters could severely disrupt normal operations and have an adverse effect on our business, financial condition 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, financial condition, 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 condition 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 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 financial condition 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 oil and 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 results of operations and impair our ability to make payments on our debt obligations or distributions to our unitholders.

Certain of our operations are subject to the jurisdiction of the FERC, and some of our operations could be subject to the jurisdiction of the FERC in the future.

TLP s Razorback and Diamondback pipelines are subject to the jurisdiction of the FERC. 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 crude oil and refined products 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.

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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 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 results of operations and cash flows.

Additionally, our subsidiary Grand Mesa is in the process of constructing a pipeline originating in Weld County, Colorado and terminating at our Cushing, Oklahoma terminal. We expect that this pipeline will be subject to FERC regulation.

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 significant portion of revenues in our water business is derived from sales of crude oil recovered during the wastewater treatment process. Our ability to recover sufficient volumes of crude oil 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 condition 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.

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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 condition 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 operating results and financial condition. 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 operating results and financial condition than if our retail propane business were less concentrated.

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 unfavorably 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 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 unfavorably impact our results of operations.

The expiration of tax credits could adversely impact the demand for biodiesel, which could unfavorably 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. Currently no such tax credit exists for transactions subsequent to December 31, 2014, 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.

Approximately 65% of the revenues of our crude oil logistics segment during the year ended March 31, 2015 were generated from our ten largest customers of the segment. Approximately 23% of the water treatment and disposal revenues of our water solutions segment during the year ended March 31, 2015 were generated from our two largest customers of the segment. Approximately 33% of the revenues of our liquids segment during the year ended March 31, 2015 were generated from our ten largest customers of the segment. Approximately 22% of the revenues of our refined products and renewables segment during the year ended

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March 31, 2015 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 results of operations.

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 financial condition, operating results 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. In addition, Grand Mesa, one of our subsidiaries, is in the process of constructing a crude oil pipeline originating in Weld County, Colorado and terminating at our Cushing, Oklahoma terminal. We anticipate that the pipeline will commence service in the second half of calendar year 2016. 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. Moreover, 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 results of operations and financial condition.

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, results of operations, financial condition 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

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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, results of operations and financial condition.

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 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. In addition, due in part to current economic conditions, including the cost of fuel, insurance, and tractors and the DOT regulatory requirements, the available pool of qualified truck drivers has been declining. 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 will create difficulties in increasing the number of our drivers for our anticipated expansion in 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 controls 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 controls. Any failure to maintain effective internal controls 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 controls over financial reporting, we can provide no assurance as to 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 trading price of our common units.

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

At March 31, 2015, we had reported goodwill and intangible assets of $2.7 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 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 TLP owns refined products terminals. These facilities depend on pipeline and storage systems that are owned and operated by third parties. Any interruption of service on the 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 affect 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.

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.

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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 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;

- 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 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

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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;
- 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;
- 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.

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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.

Although we control TLP through our ownership of its general partner, TLP s general partner owes fiduciary duties to TLP s unitholders, which may conflict with our interests.

Conflicts of interest exist and may arise in the future as a result of the relationships between us and our affiliates, on the one hand, and TLP and its limited partners, on the other hand. The directors and officers of TLP s general partner have fiduciary duties to manage TLP in a manner beneficial to us. At the same time, TLP s general partner has fiduciary duties to manage TLP in a manner beneficial to TLP and its limited partners. The board of directors of TLP s general partner will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. The resolution of these conflicts may not always be in our best interest.

For example, conflicts of interest with TLP may arise in the following situations:

- the interpretation and enforcement of contractual obligations between us and our affiliates, on the one hand, and TLP, on the other hand;

- the determination of the amount of cash to be distributed to TLP s limited partners and the amount of cash to be reserved for the future conduct of TLP s business; and

- the determination whether to make borrowings under TLP s revolving credit facility to pay distributions to its limited partners.

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.

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.

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)

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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 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 U.S. federal income tax purposes.

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.

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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 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 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 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.

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

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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.

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.

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

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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, Customer Dispute, and Contractual Disputes 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 25, 2015, there were approximately 300 common unitholders of record which does not include unitholders for whom common units may be held in street name.

The following table summarizes, for the periods indicated, the high and low sales prices per common unit, 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
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
2014 Fiscal Year			
Fourth Quarter	$ 38.14	$ 33.33	$ 0.5313
Third Quarter	35.10	30.10	0.5113
Second Quarter	33.90	27.75	0.4938
First Quarter	30.69	26.08	0.4775

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. TLP s partnership agreement also requires that, within 45 days after the end of each quarter, it distribute all of its available cash (as defined in its partnership agreement) to its unitholders as of the record date.

Minimum Quarterly Distribution

Our partnership agreement provided that, during the subordination period, the common units were entitled to distributions of available cash each quarter in an amount equal to the minimum quarterly distribution, which was $0.3375 per common unit, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash were permitted on the subordinated units. Arrearages did not apply to and therefore were not paid on the subordinated units. The effect of the subordinated units was to increase the likelihood that, during the subordination period, available cash was sufficient to fully fund cash distributions on the common units in an amount equal to the minimum quarterly distribution. The subordination period ended in August 2014, at which time all outstanding subordinated units were converted into common units on a one-for-one basis.

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 conversion of outstanding subordinated units or 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.

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Incentive Distribution Rights

Our general partner also currently holds IDRs which represent a variable interest in our distributions. IDRs entitle our general partner to receive increasing percentages, up to a maximum of 48.1%, of the cash we distribute from operating surplus (as defined in our partnership agreement) in excess of $0.388125 per unit per quarter. The maximum distribution of 48.1% includes distributions paid to our general partner on its 0.1% general partner interest and assumes that our general partner maintains its general partner interest at 0.1%. 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, 2015, we completed three 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 January 2015, we issued 132,100 common units to the sellers of a retail propane business. During February 2015, we issued 7,396,973 common units to the sellers of a natural gas liquids storage business. During the fourth quarter of fiscal year 2015, we issued 1,322,032 common units to the sellers of three water treatment and disposal facilities.

In July 2014, we issued $400.0 million of 5.125% Senior Notes Due 2019 in a private placement exempt from registration under the Securities Act pursuant to Rule 144A and Regulation S under the Securities Act. We received net proceeds of $393.5 million, after the initial purchasers discount of $6.0 million and offering costs of $0.5 million.

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

We were formed on September 8, 2010, but had no operations through September 30, 2010. In October 2010, we acquired the wholesale propane and terminaling business of NGL Supply, which refers to NGL Supply, Inc. for periods prior to our formation and refers to NGL Supply, LLC, a wholly owned subsidiary of NGL Energy Operating LLC, for periods after our formation, and the retail propane business of Hicksgas, which refers to the combined assets and operations of Hicksgas Gifford, Inc. (Gifford), and Hicksgas, LLC, a wholly owned subsidiary of NGL Energy Operating LLC (Hicks LLC). We do not have our own historical financial statements for periods prior to our formation. The following table shows selected historical financial and operating data for NGL Energy Partners LP and NGL Supply (the deemed acquirer for accounting purposes in our formation) for the periods and as of the dates indicated. The financial statements of NGL Supply became our historical financial statements for all periods prior to October 1, 2010. 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.

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The selected consolidated historical financial data (excluding volume information) at March 31, 2015, 2014, and 2013 and for each of the three years in the period ended March 31, 2015 are 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, 2012 and 2011 and for the six months ended March 31, 2011 are derived from our financial records. The selected consolidated historical financial data (excluding volume information) at September 30, 2010 and for the six months then ended are derived from the financial records of NGL Supply.

	NGL Energy Partners LP					NGL Supply, Inc.
		Year Ended March 31,			Six Months Ended March 31,	Six Months Ended September 30,
	2015	2014	2013	2012	2011	2010
	(in thousands, except per unit and per share data)					
Income Statement Data (1)						
Total revenues	$ 16,802,057	$ 9,699,274	$ 4,417,767	$ 1,310,473	$ 622,232	$ 316,943
Total cost of sales	15,958,207	9,132,699	4,039,110	1,217,023	583,032	310,908
Operating income (loss)	87,111	106,565	87,307	15,030	14,837	(3,795)
Interest expense	110,123	58,854	32,994	7,620	2,482	372
Loss on early extinguishment of debt			5,769			
Net income (loss) attributable to parent equity	16,661	47,655	47,940	7,876	12,679	(2,515)
Basic and diluted income (loss) per common unit	(0.29)	0.51	0.96	0.32	1.16	
Basic and diluted loss per common share						(128.46)
Cash Flows Data (1)						
Net cash provided by (used in) operating activities	$ 262,394	$ 85,236	$ 132,634	$ 90,329	$ 34,009	$ (30,749)
Cash distributions paid per common unit (subsequent to IPO)	2.37	2.01	1.69	0.85		
Cash distributions paid per common unit (prior to IPO)				0.35		
Cash distributions paid per common share						357.09
Capital expenditures:						
Purchases of long-lived assets	203,760	165,148	72,475	7,544	1,440	280
Purchases of pipeline capacity allocations	24,218					
Purchase of equity interest in Grand Mesa Pipeline	310,000					
Acquisitions of businesses, including acquired working capital, net of cash acquired	960,922	1,268,810	490,805	297,401	17,400	123
Balance Sheet Data - Period End (1)(2)						
Total assets	$ 6,547,501	$ 4,147,631	$ 2,291,618	$ 749,519	$ 163,833	$ 148,596
Total long-term obligations, exclusive of current maturities	2,761,385	1,640,894	742,641	199,389	65,936	18,940
Total equity	2,673,120	1,531,853	889,418	405,329	47,353	36,811
Volume Information (1)						
Retail propane and distillates sold (gallons)	204,141	197,326	173,232	79,886	34,932	3,747
	1,285,707	1,190,106	912,625	659,921	372,504	226,330

Wholesale propane sold (gallons) (3)						
Wholesale other products sold (gallons)	825,514	786,671	505,529	134,999	49,465	46,092
Crude oil sold (barrels)	83,864	46,107	24,373			
Water delivered (barrels)	139,569	62,774	25,009			
Refined products sold (barrels)	68,043	9,833				

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

(2) Certain balance sheet data at March 31, 2014 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).

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

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 acquisitons, as described under Part I, Item 1 Business Acquisitions. At March 31, 2015, our operations include:

- Our crude oil logistics segment, the assets of which include owned and leased crude oil storage terminals, owned and leased pipeline injection stations, a fleet of owned trucks and trailers, a fleet of owned and leased railcars, a fleet of owned and leased barges and towboats, and a 50% interest in a crude oil pipeline. Our crude oil logistics segment purchases crude oil from producers and transports it 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 treatment and disposal facilities. Our water solutions segment generates revenues from the treatment and disposal of wastewater generated from crude oil and natural gas production, from the sale of recycled water and recovered hydrocarbons, and from the disposal of solids such as tank bottoms and drilling fluids.

- 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 services through its 21 owned terminals throughout the United States and railcar transportation services through its fleet of leased railcars. Our liquids segment purchases propane, butane, and other products from refiners, processing plants, producers, and other parties, and sells the products to retailers, refiners, petrochemical plants, and other participants in the wholesale markets.

- 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 also own the 2.0% general partner interest and a 19.6% limited partner interest in TransMontaigne Partners L.P. (TLP), which conducts refined products terminaling operations. TLP also owns a 42.5% interest in Battleground Oil Specialty Terminal Company LLC (BOSTCO) and a 50% interest in Frontera Brownsville LLC, which are entities that own refined products storage facilities.

Crude Oil Logistics

Our crude oil logistics segment purchases crude oil from producers and transports it for resale at owned and leased pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs. We attempt to reduce our exposure to price fluctuations by using back-to-back contracts whenever possible. In addition, we enter into forward contracts, financial swaps, and commodity spread trades as economic hedges of our physical forward sales and purchase contracts with our customers and suppliers.

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. We utilize 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. We also seek to maximize margins by blending crude oil of varying properties.

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The range of low and high spot crude oil prices per barrel of NYMEX West Texas Intermediate Crude Oil at Cushing, Oklahoma and the prices at period end were as follows:

	Spot Price Per Barrel		
Year Ended March 31,	**Low**	**High**	**At Period End**
2015	$ 43.46	$ 107.26	$ 47.60
2014	86.68	110.53	101.58
2013	77.69	106.16	97.23

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

Water Solutions

Our water solutions segment generates revenues from the treatment and disposal of wastewater generated from crude oil and natural gas production, from the sale of recycled water and recovered hydrocarbons, and from the disposal of solids such as tank bottoms and drilling fluids. 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 based upon producers expectations about the profitability of drilling new wells. The primary customers of our facility in Wyoming have committed to deliver a specified minimum volume of water to our facility under long-term contracts. The primary customers of our facilities in the Colorado have committed to deliver to our facilities all wastewater produced at wells in a designated area. One customer in Texas has committed to deliver at least 50,000 barrels of wastewater per day to our facilities. Most of the customers at our other facilities are not under volume commitments.

Liquids

Our liquids segment purchases propane, butane, and other products from refiners, processing plants, producers, and other parties, and sells the products to retailers, refiners, petrochemical plants, and other participants in the wholesale markets. Our liquids segment owns 21 terminals, operates a fleet of leased railcars, and leases underground storage capacity. We attempt to reduce our exposure to the impact of price fluctuations by using back-to-back contracts and pre-sale agreements that allow us to lock in a margin on a percentage of our winter volumes. We also attempt to reduce our exposure to the impact of price fluctuations by entering into swap agreements whereby we agree to pay a floating rate and receive a fixed rate on a specified notional amount of product. We enter into these agreements as economic hedges against the potential decline in the value of a portion of our inventory.

Our wholesale business is a cost-plus business that can be affected both by 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 margins we realize in our wholesale business are substantially less on a per gallon basis than 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 range of low and high spot propane prices per gallon at Conway, Kansas, and Mt. Belvieu, Texas, two of our main pricing hubs, and the prices at period end were as follows:

	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**
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
2013	0.50	0.96	0.90	0.71	1.22	0.96

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The range of low and high spot butane prices per gallon at Mt. Belvieu, Texas and the prices at period end were as follows:

	Spot Price Per Gallon		
Year Ended March 31,	Low	High	At Period End
2015	$ 0.60	$ 1.30	$ 0.63
2014	1.08	1.64	1.26
2013	1.14	1.93	1.45

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

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. 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 differential between our sales prices and our total product costs, including transportation and storage. Historically, we have been successful in passing on price increases to our customers. We monitor propane prices daily and adjust our retail prices to maintain expected margins by passing on the wholesale costs to our customers. Volatility in commodity prices may 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.

Refined Products and Renewables

Our refined products and renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations. Of the sales volumes of our refined products and renewables segment during the year ended March 31, 2015, approximately 93% were refined products and approximately 7% were renewables.

We purchase refined petroleum products primarily in the Gulf Coast, East Coast, 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.

The range of low and high spot gasoline prices per gallon using NYMEX gasoline prompt-month futures and the prices at period end were as follows:

	Spot Price Per Gallon		
Year Ended March 31,	**Low**	**High**	**At Period End**
2015	$ 1.27	$ 3.13	$ 1.78
2014 (1)	2.60	3.02	2.91

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

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The range of low and high spot diesel prices per gallon using NYMEX ULSD prompt-month futures and the prices at period end were as follows:

	Spot Price Per Gallon		
Year Ended March 31,	Low	High	At Period End
2015	$ 1.62	$ 3.05	$ 1.72
2014 (1)	2.90	3.28	2.93

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

Recent Developments

Grand Mesa Pipeline, LLC

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). Grand Mesa is constructing a crude oil pipeline originating in Weld County, Colorado and terminating at our Cushing, Oklahoma terminal. In October 2014, Grand Mesa completed a successful open season in which it received the requisite support, in the form of ship-or-pay volume commitments from multiple shippers, to begin construction of a 20-inch pipeline system. In November 2014, we acquired RimRock s 50% ownership interest in Grand Mesa for $310.0 million in cash. We anticipate that the pipeline will commence service in the second half of calendar year 2016. Rimrock Midstream, LLC s Platte River gathering system, which is currently under development, is expected to deliver volumes from multiple shippers to Grand Mesa s northern origin near Lucerne, Colorado.

Acquisitions

Acquisitions of businesses have had a significant impact on the comparability of our results of operations during the years ended March 31, 2015, 2014 and 2013. These transactions are described under Part I, Item 1 Business Acquisitions.

Consolidated Results of Operations

The following table summarizes our consolidated statements of operations for the years ended March 31, 2015, 2014, and 2013:

	Year Ended March 31,		
	2015	2014	2013

		(in thousands)	
Total revenues	$ 16,802,057	$ 9,699,274	$ 4,417,767
Total cost of sales	15,958,207	9,132,699	4,039,110
Operating expenses	372,176	259,799	169,612
Loss on disposal or impairment of assets, net	41,184	3,597	187
General and administrative expense	149,430	75,860	52,698
Depreciation and amortization	193,949	120,754	68,853
Operating income	87,111	106,565	87,307
Earnings of unconsolidated entities	12,103	1,898	
Interest expense	(110,123)	(58,854)	(32,994)
Loss on early extinguishment of debt			(5,769)
Other income, net	37,171	86	1,521
Income before income taxes	26,262	49,695	50,065
Income tax (provision) benefit	3,622	(937)	(1,875)
Net income	29,884	48,758	48,190
Less: Net income allocated to general partner	(45,679)	(14,148)	(2,917)
Less: Net income attributable to noncontrolling interests	(13,223)	(1,103)	(250)
Net income (loss) allocated to limited partners	$ (29,018)	$ 33,507	$ 45,023

See the detailed discussion of revenues, cost of sales, operating expenses, loss on disposal or impairment of assets, net, general and administrative expense, depreciation and amortization expense and operating income by segment below. The acquisitions described under Part I, Item 1 Business

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Acquisitions have had a significant impact on the comparability of our results of operations during the years ended March 31, 2015, 2014 and 2013.

Non-GAAP Financial Measures

The following table reconciles net income attributable to parent equity to our EBITDA and Adjusted EBITDA (each as hereinafter defined), which are non-GAAP financial measures:

	Year Ended March 31, 2015	2014 (in thousands)	2013
Net income attributable to parent equity	$ 16,661	$ 47,655	$ 47,940
Income tax provision (benefit)	(3,676)	937	1,875
Interest expense	106,594	58,871	32,994
Loss on early extinguishment of debt			5,769
Depreciation and amortization	191,998	127,821	73,739
EBITDA	311,577	235,284	162,317
Net unrealized (gains) losses on derivatives	7,559	(1,327)	5,275
Lower of cost or market adjustments	16,806		
Loss on disposal or impairment of assets, net	41,274	3,597	187
Equity-based compensation expense (1)	42,890	17,804	10,138
Adjusted EBITDA	$ 420,106	$ 255,358	$ 177,917

(1) 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. The amounts above include $10.1 million of compensation expense during the year ended March 31, 2015 associated with these bonuses. As a result, the amount in this table for the year ended March 31, 2015 is greater than the amount of equity-based compensation reported in Note 11 to our consolidated financial statements included in this Annual Report on Form 10-K (Annual Report).

We define EBITDA as net income attributable to parent equity plus interest expense, loss on early extinguishment of debt, income taxes, and depreciation and amortization expense. We define Adjusted EBITDA as EBITDA excluding net unrealized gains or losses on derivatives, lower of cost or market adjustments, gains or losses on the disposal or impairment of assets, and equity-based compensation expense. 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 accounting principles generally accepted in the United States (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 and 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 unrealized gains and losses on derivatives and realized 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 draw such a distinction between realized and unrealized gains and losses on the derivatives of our refined products and renewables segment. The primary hedging strategy of this segment is to hedge against the risk of declines in the value of inventory over the course of the contract cycle, and most of the hedges are six months to one year in duration at inception.

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 crude oil we expect to recover in future months. During the year ended March 31, 2015, we settled certain derivative contracts that related to crude oil we expect to recover in the months from April 2015 through September 2015 and realized a gain of

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$17.9 million. Of this gain, $9.4 million and $8.5 million were attributable to derivatives with scheduled settlement dates during the quarters ending June 30, 2015 and September 30, 2015, respectively.

During the year ended March 31, 2015, we recorded $7.4 million of expense related to legal and advisory costs associated with acquisitions and $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).

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:

	Year Ended March 31, 2015	2014	2013
		(in thousands)	
Reconciliation to consolidated statements of operations:			
Depreciation and amortization per EBITDA table	$ 191,998	$ 127,821	$ 73,739
Intangible asset amortization recorded to cost of sales	(7,767)	(6,172)	(5,285)
Depreciation and amortization of unconsolidated entities	(18,979)	(1,638)	
Depreciation and amortization attributable to noncontrolling interests	28,697	743	399
Depreciation and amortization per consolidated statements of operations	$ 193,949	$ 120,754	$ 68,853
Reconciliation to consolidated statements of cash flows:			
Depreciation and amortization per EBITDA table	$ 191,998	$ 127,821	$ 73,739
Amortization of debt issuance costs recorded to interest expense	8,759	5,727	3,375
Depreciation and amortization of unconsolidated entities	(18,979)	(1,638)	
Depreciation and amortization attributable to noncontrolling interests	28,697	743	399
Depreciation and amortization per consolidated statements of cash flows	$ 210,475	$ 132,653	$ 77,513

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

	Capital Expenditures		
Year Ended March 31,	Expansion	Maintenance	Total
		(in thousands)	
2015	$ 169,207	$ 40,746	$ 209,953
2014	132,948	32,200	165,148
2013	58,675	13,800	72,475

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 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 expanded our water solutions business through numerous acquisitions of water disposal and transportation businesses, including High Roller Wells Big Lake SWD No. 1, Ltd. (Big Lake) in July 2013, Oilfield Water Lines LP (collectively, OWL) in August 2013, Coastal Plains Disposal #1, LLC (Coastal) in September 2013, and facilities acquired pursuant to development agreements. Our refined products and renewables businesses began with our December 2013 acquisition of Gavilon Energy and 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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Volumes

The following table summarizes the volume of product sold and water delivered during the years ended March 31, 2015 and 2014. Volumes shown in the following table include intersegment sales.

Segment	Year Ended March 31, 2015	2014	Change
		(in thousands)	
Crude oil logistics			
Crude oil sold (barrels)	83,864	46,107	37,757
Water solutions			
Water delivered (barrels)	139,569	62,774	76,795
Liquids			
Propane sold (gallons)	1,285,707	1,190,106	95,601
Other products sold (gallons)	825,514	786,671	38,843
Retail propane			
Propane sold (gallons)	169,279	162,361	6,918
Distillates sold (gallons)	34,862	34,965	(103)
Refined products and renewables			
Refined products sold (barrels)	68,043	9,833	58,210

Revenues and Cost of Sales by Segment

Our revenues and cost of sales during the year ended March 31, 2015 by segment are as follows:

	Revenues	Cost of Sales	Product Margin
		(In thousands)	
Crude oil logistics	$ 6,665,220	$ 6,590,313	$ 74,907
Water solutions	200,042	(30,506)	230,548
Liquids	2,405,841	2,273,630	132,211
Retail propane	489,197	278,538	210,659
Refined products and renewables	7,232,772	7,036,541	196,231
Corporate and other	1,916	2,583	(667)
Eliminations	(192,931)	(192,892)	(39)
Total	$ 16,802,057	$ 15,958,207	$ 843,850

Operating Income (Loss) by Segment

Our operating income (loss) by segment is as follows:

	Year Ended March 31,		
Segment	**2015**	**2014**	**Change**
	(in thousands)		
Crude oil logistics	$ (35,832)	$ 678	$ (36,510)
Water solutions	45,031	10,317	34,714
Liquids	45,072	71,888	(26,816)
Retail propane	64,075	61,285	2,790
Refined products and renewables	54,567	6,514	48,053
Corporate and other	(85,802)	(44,117)	(41,685)
Operating income	$ 87,111	$ 106,565	$ (19,454)

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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 (in thousands)	Change
Revenues:			
Crude oil sales	$ 6,609,685	$ 4,559,923	$ 2,049,762
Crude oil transportation and other	55,535	36,469	19,066
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)
Loss (gain) on disposal or impairment of assets, net	3,759	(171)	3,930
General and administrative expenses	15,564	4,487	11,077
Depreciation and amortization expense	38,626	22,111	16,515
Total expenses	6,701,052	4,595,714	2,105,338
Segment operating income (loss) (2)	$ (35,832)	$ 678	$ (36,510)

(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 which the producers paid us specified amounts. 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.

Revenues. Our crude oil logistics segment generated $6.6 billion of revenue from crude oil sales during the year ended March 31, 2015, selling 83.9 million barrels at an average price of $78.81 per barrel. During the year ended March 31, 2014, our crude oil logistics segment generated $4.6 billion of revenue from crude oil sales, selling 46.1 million barrels at an average price of $98.90 per barrel. The decrease in revenue per barrel was due primarily to the sharp decline in crude oil prices during the year ended March 31, 2015. The most significant driver of the increase in our sales volumes was the acquisition of Gavilon Energy in December 2013.

Crude oil transportation and other revenues were $55.5 million during the year ended March 31, 2015, compared to $36.5 million of crude oil transportation and other revenues during the year ended March 31, 2014. This increase was due primarily to the Crescent acquisition in July 2013 and the Gavilon Energy acquisition in December 2013.

Cost of Sales. Our cost of crude oil sold was $6.6 billion during the year ended March 31, 2015, as we sold 83.9 million barrels at an average cost of $78.58 per barrel. Our cost of sales during the year ended March 31, 2015 was increased by $7.4 million of net unrealized losses on derivatives and was reduced by $37.4 million of net realized gains on derivatives. During the year ended March 31, 2014, our cost of crude oil sold was $4.5 billion, as we sold 46.1 million barrels at an average cost of $97.93 per barrel. Our cost of sales during the year ended March 31, 2014 was increased by $2.2 million of net unrealized losses on derivatives and by $5.1 million of net realized losses on derivatives.

Product margins were lower during the year ended March 31, 2015 than during the year ended March 31, 2014, due primarily to the sharp decline in crude oil prices during the year ended March 31, 2015. This had an adverse impact on margins, due to the

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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 markets were backwardated for most of the year.

Operating Expenses. Our crude oil logistics segment incurred $52.8 million of operating expenses during the year ended March 31, 2015, compared to $54.0 million of operating expenses during the year ended March 31, 2014. This decrease was due primarily to lower incentive compensation expense, as $7.3 million of compensation otherwise payable in cash will instead be paid in common units, and as a result the related expense was recorded within corporate and other, rather than within the crude oil logistics segment, 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.

Loss (Gain) on Disposal or Impairment of Assets, Net. Our crude oil logistics segment incurred $3.8 million of losses on disposal or impairment of assets during the year ended March 31, 2015 and recorded a gain of $0.2 million on the disposal of assets during the year ended March 31, 2014. 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.

General and Administrative Expenses. Our crude oil logistics segment incurred $15.6 million of general and administrative expenses during the year ended March 31, 2015, compared to $4.5 million of general and administrative expenses during the year ended March 31, 2014. This 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. Our crude oil logistics segment incurred $38.6 million of depreciation and amortization expense during the year ended March 31, 2015, compared to $22.1 million of depreciation and amortization expense during the year ended March 31, 2014. This increase was due primarily to acquisitions and capital expansions.

Water Solutions

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

	Year Ended March 31, 2015	Year Ended March 31, 2014	Change
	(in thousands)		
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	101,313	59,184	42,129
Loss on disposal or impairment of assets, net	7,504	2,994	4,510
General and administrative expenses	3,082	3,762	(680)
Depreciation and amortization expense	73,618	55,105	18,513
Total expenses	155,011	132,783	22,228
Segment operating income	$ 45,031	$ 10,317	$ 34,714

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

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The following tables summarize activity separated among the following categories:

- Facilities we owned prior to March 31, 2013;
- Facilities we developed subsequent to March 31, 2013; and
- Facilities we acquired subsequent to March 31, 2013.

Service Fee Revenues. The following table summarizes our service fee revenue (in thousands, except per barrel amounts):

	Year Ended March 31, 2015			Year Ended March 31, 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	63,465	$ 1.03	$ 51,908	46,628	$ 1.11
Recently developed facilities	1,667	3,193	0.52			
Recently acquired facilities	38,474	72,911	0.53	6,253	16,146	0.39
Total	$ 105,682	139,569		$ 58,161	62,774	

The volumes of our existing facilities were higher during the year ended March 31, 2015 than during the year ended March 31, 2014, due primarily to increased demand from customers.

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 recovered hydrocarbon revenue (in thousands, except per barrel amounts):

	Year Ended March 31, 2015			Year Ended March 31, 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	63,465	$ 0.57	$ 40,393	46,628	$ 0.87
	1,637	3,193	0.51			

Recently developed facilities								
Recently acquired facilities		43,764	72,911	0.60		27,234	16,146	1.69
Total	$	81,762	139,569		$	67,627	62,774	

The decrease in revenue per barrel associated with recovered hydrocarbons was due primarily to the sharp decline in crude oil prices during the year ended March 31, 2015.

Our water solutions segment generated $10.8 million of water transportation revenue during the year ended March 31, 2015, compared to $17.3 million of water transportation revenue during the year ended March 31, 2014. The decrease resulted from the sale of our water transportation business during September 2014.

Cost of Sales. We entered 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 was reduced by $2.8 million of net unrealized gains on derivatives and $34.0 million of net realized gains on derivatives during the year ended March 31, 2015. Our cost of sales was increased by $0.6 million of net unrealized losses on derivatives and $1.4 million of net realized losses on derivatives during the year ended March 31, 2014. 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.

Our other cost of sales was $6.3 million during the year ended March 31, 2015, compared to $9.8 million during the year ended March 31, 2014. These costs related primarily to our water transportation business, which we sold during September 2014.

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Operating Expenses. The following table summarizes our operating expenses (in thousands):

	Year Ended March 31, 2015	2014	Change
Existing facilities	$ 46,324	$ 36,381	$ 9,943
Recently developed facilities	1,032		1,032
Recently acquired facilities	53,957	22,803	31,154
Total	$ 101,313	$ 59,184	$ 42,129

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

Loss on Disposal or Impairment of Assets, Net. Our water solutions segment incurred $7.5 million of losses on disposal or impairment of assets during the year ended March 31, 2015 and $3.0 million of losses on disposal or impairment of assets during the year ended March 31, 2014. 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 the 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.

General and Administrative Expenses. Our water solutions segment incurred $3.1 million of general and administrative expenses during the year ended March 31, 2015, compared to $3.8 million of general and administrative expenses during the year ended March 31, 2014.

Depreciation and Amortization Expense. Our water solutions segment incurred $73.6 million of depreciation and amortization expense during the year ended March 31, 2015, compared to $55.1 million of depreciation and amortization expense during the year ended March 31, 2014. 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.

Liquids

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

	Year Ended March 31, 2015	2014 (in thousands)	Change
Revenues:			
Propane sales	$ 1,263,113	$ 1,632,948	$ (369,835)
Other product sales	1,111,434	1,231,965	(120,531)

Other revenues	31,294	31,062	232
Total revenues (1)	2,405,841	2,895,975	(490,134)
Expenses:			
Cost of sales - propane	1,204,499	1,559,266	(354,767)
Cost of sales - other products	1,053,630	1,179,944	(126,314)
Cost of sales - other	15,501	24,439	(8,938)
Operating expenses	35,580	37,672	(2,092)
Loss on disposal or impairment of assets, net	29,775	5,305	24,470
General and administrative expenses	8,271	6,443	1,828
Depreciation and amortization expense	13,513	11,018	2,495
Total expenses	2,360,769	2,824,087	(463,318)
Segment operating income	$ 45,072	$ 71,888	$ (26,816)

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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.

Revenues. Our liquids segment generated $1.3 billion of wholesale propane sales revenue during the year ended March 31, 2015, selling 1.3 billion gallons at an average price of $0.98 per gallon. During the year ended March 31, 2014, our liquids segment generated $1.6 billion of wholesale propane sales revenue, selling 1.2 billion gallons at an average price of $1.37 per gallon. 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 liquids segment generated $1.1 billion of other wholesale products sales revenue during the year ended March 31, 2015, selling 825.5 million gallons at an average price of $1.35 per gallon. During the year ended March 31, 2014, our liquids segment generated $1.2 billion of other wholesale products sales revenue, selling 786.7 million gallons at an average price of $1.57 per gallon.

Our liquids segment generated $31.3 million of other revenues during the year ended March 31, 2015. This revenue includes storage sublease income, terminal gain/loss and income generated from the operation of a terminal for a customer.

Cost of Sales. Our cost of wholesale propane sales was $1.2 billion during the year ended March 31, 2015, as we sold 1.3 billion gallons at an average cost of $0.94 per gallon. 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. During the year ended March 31, 2014, our cost of wholesale propane sales was $1.6 billion, as we sold 1.2 billion gallons at an average cost of $1.31 per gallon. 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. Our product margins for propane sales are summarized below (in thousands, except per gallon amounts):

	Year Ended March 31,			
		2015		**2014**
Propane revenues	$	1,263,113	$	1,632,948
Propane cost of sales		(1,204,499)		(1,559,266)
Propane product margin	$	58,614	$	73,682
Propane sold (gallons)		1,285,707		1,190,106
Product margin per gallon	$	0.05	$	0.06

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.

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Our cost of sales of other products was $1.1 billion during the year ended March 31, 2015, as we sold 825.5 million gallons at an average cost of $1.28 per gallon. 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. During the year ended March 31, 2014, our cost of sales of other products was $1.2 billion, as we sold 786.7 million gallons at an average cost of $1.50 per gallon. 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. Our per-gallon product margins during the year ended March 31, 2015 were similar to those during the year ended March 31, 2014, as summarized below (in thousands, except per gallon amounts):

	Year Ended March 31,			
		2015		2014
Other products revenues	$	1,111,434	$	1,231,965
Other products cost of sales		(1,053,630)		(1,179,944)
Other products product margin	$	57,804	$	52,021
Other products sold (gallons)		825,514		786,671
Product margin per gallon	$	0.07	$	0.07

Operating Expenses. Our liquids segment incurred $35.6 million of operating expenses during the year ended March 31, 2015, compared to $37.7 million of operating expenses during the year ended March 31, 2014. This decrease was due primarily to lower compensation expense, as $5.0 million of compensation otherwise payable in cash was instead paid in common units, and as a result the related expense was recorded within corporate and other, rather than within the liquids segment.

Loss on Disposal or Impairment of Assets, Net. Our liquids segment incurred $29.8 million of losses on disposal or impairment of assets during the year ended March 31, 2015, and $5.3 million of losses on disposal or impairment of assets during the year ended March 31, 2014. During the year ended March 31, 2015, we recorded a loss of $29.9 million on 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.

General and Administrative Expenses. Our liquids segment incurred $8.3 million of general and administrative expenses during the year ended March 31, 2015, compared to $6.4 million of general and administrative expenses during the year ended March 31, 2014. This increase was due primarily to expanded operations.

Depreciation and Amortization Expense. Our liquids segment incurred $13.5 million of depreciation and amortization expense during the year ended March 31, 2015, compared to $11.0 million of depreciation and amortization expense during the year ended March 31, 2014.

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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)		
Revenues:			
Propane sales	$ 347,575	$ 388,225	$ (40,650)
Distillate sales	106,037	127,672	(21,635)
Other revenues	35,585	35,918	(333)
Total revenues	489,197	551,815	(62,618)
Expenses:			
Cost of sales - propane	181,655	233,110	(51,455)
Cost of sales - distillates	85,329	109,058	(23,729)
Cost of sales - other	11,554	11,531	23
Operating expenses	102,405	96,936	5,469
General and administrative expenses	12,352	11,017	1,335
Depreciation and amortization expense	31,827	28,878	2,949
Total expenses	425,122	490,530	(65,408)
Segment operating income	$ 64,075	$ 61,285	$ 2,790

Revenues. Our retail propane segment generated revenue of $347.6 million from propane sales during the year ended March 31, 2015, selling 169.3 million gallons at an average price of $2.05 per gallon. During the year ended March 31, 2014, our retail propane segment generated $388.2 million of revenue from propane sales, selling 162.4 million gallons at an average price of $2.39 per gallon. The increase in volume sold was due in part to the growth of our business through acquisitions, partially offset by lower demand due to the fact that weather conditions were warmer in some markets in the winter of the year ended March 31, 2015 than during the winter of the prior year.

Our retail propane segment generated revenue of $106.0 million from distillate sales during the year ended March 31, 2015, selling 34.9 million gallons at an average price of $3.04 per gallon. During the year ended March 31, 2014, our retail propane segment generated $127.7 million of revenue from distillate sales, selling 35.0 million gallons at an average price of $3.65 per gallon.

Cost of Sales. Our cost of retail propane sales was $181.7 million during the year ended March 31, 2015, as we sold 169.3 million gallons at an average cost of $1.07 per gallon. During the year ended March 31, 2014, our cost of retail propane sales was $233.1 million, as we sold 162.4 million gallons at an average cost of $1.44 per gallon.

Our cost of distillate sales was $85.3 million during the year ended March 31, 2015, as we sold 34.9 million gallons at an average cost of $2.45 per gallon. During the year ended March 31, 2014, our cost of distillate sales was $109.1 million, as we sold 35.0 million gallons at an average cost of $3.12 per gallon.

Operating Expenses. Our retail propane segment incurred $102.4 million of operating expenses during the year ended March 31, 2015, compared to $96.9 million of operating expenses during the year ended March 31, 2014. 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.

Depreciation and Amortization Expense. Our retail propane segment incurred $31.8 million of depreciation and amortization expense during the year ended March 31, 2015, compared to $28.9 million of depreciation and amortization expense 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 expanded with our July 2014 acquisition of TransMontaigne.

	Year Ended March 31,					
	2015		2014		Change	
			(in thousands)			
Revenues:						
Refined products sales (1)	$	6,684,045	$	1,180,895	$	5,503,150
Renewables sales		473,885		176,781		297,104
Service fees		74,842				74,842
Total revenues		7,232,772		1,357,676		5,875,096
Expenses:						
Cost of sales - refined products		6,574,545		1,172,754		5,401,791
Cost of sales - renewables		461,996		171,422		290,574
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		7,178,205		1,351,162		5,827,043
Segment operating income	$	54,567	$	6,514	$	48,053

(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.

Revenues. Our refined products sales revenue was $6.7 billion during the year ended March 31, 2015, selling 68.0 million barrels at an average price of $98.23 per barrel. Our refined products sales revenue was $1.2 billion during the year ended March 31, 2014, selling 9.8 million barrels at an average price of $120.10 per barrel.

Our renewables sales revenue was $473.9 million during the year ended March 31, 2015, selling 5.3 million barrels at an average price of $89.11 per barrel. Our renewables sales revenue was $176.8 million during the year ended March 31, 2014.

Our refined products and renewables segment generated $74.8 million of service fee revenue during the year ended March 31, 2015, which was due primarily to TLP s refined products terminaling operations.

Cost of Sales. Our cost of refined products sales was $6.6 billion during the year ended March 31, 2015, as we sold 68.0 million barrels at an average cost of $96.62 per barrel. Our cost of refined products sales was $1.2 billion during the year ended March 31, 2014, as we sold 9.8 million barrels at an average cost of $119.27 per barrel. Our refined product margins are summarized below (in thousands, except per barrel and per gallon amounts):

	Year Ended March 31,	
	2015	2014
Revenues	$ 6,684,045	$ 1,180,895
Cost of sales	(6,574,545)	(1,172,754)
Product margin	$ 109,500	$ 8,141
Refined products sold (barrels)	68,043	9,833
Product margin per barrel	$ 1.61	$ 0.83
Product margin per gallon	$ 0.04	$ 0.02

Our cost of renewables sales was $462.0 million during the year ended March 31, 2015, as we sold 5.3 million barrels at an average cost of $86.87 per barrel. Our cost of renewables sales was $171.4 million during the year ended March 31, 2014. Our renewables product margins for the year ended March 31, 2015 are summarized below (in thousands, except per barrel and per gallon amounts):

Revenues	$ 473,885
Cost of sales	(461,996)
Product margin	$ 11,889
Renewables sold (barrels)	5,318
Product margin per barrel	$ 2.24
Product margin per gallon	$ 0.05

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 $8.7 million related to these tax credits.

Operating Expenses. Our refined products and renewables segment incurred $82.6 million of operating expenses during the year ended March 31, 2015, compared to $6.2 million of operating expenses during the year ended March 31, 2014. Of the operating expenses during the year ended March 31, 2015, $48.2 million was attributable to TLP.

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General and Administrative Expenses. Our refined products and renewables segment incurred $26.1 million of general and administrative expenses during the year ended March 31, 2015, compared to $0.2 million of general and administrative expenses during the year ended March 31, 2014. General and administrative expenses during the year ended March 31, 2015 were increased by $0.5 million 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 $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, $15.0 million was attributable to TLP.

Depreciation and Amortization Expense. Our refined products and renewables segment incurred $32.9 million of depreciation and amortization expense during the year ended March 31, 2015, compared to $0.6 million of depreciation and amortization expense during the year ended March 31, 2014. This 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, $28.7 million was attributable to TLP.

Corporate and Other

The operating loss within corporate and other includes the following components:

	Year Ended March 31, 2015	Year Ended March 31, 2014 (in thousands)	Change
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 expenses	(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 secment 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.

Acquisition expenses during the year ended March 31, 2015 related primarily to the acquisitions of TransMontaigne and Sawtooth NGL Caverns, LLC (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.

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.

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Year Ended March 31, 2014

Compared to Year Ended March 31, 2013

Volumes

The following table summarizes the volume of product sold and water delivered for the years ended March 31, 2014 and 2013. Volumes shown in the following table include intersegment sales.

Segment	Year Ended March 31, 2014	2013	Change
		(in thousands)	
Crude oil logistics			
Crude oil sold (barrels)	46,107	24,373	21,734
Water solutions			
Water delivered (barrels)	62,774	25,009	37,765
Liquids			
Propane sold (gallons)	1,190,106	912,625	277,481
Other products sold (gallons)	786,671	505,529	281,142
Retail propane			
Propane sold (gallons)	162,361	144,379	17,982
Distillates sold (gallons)	34,965	28,853	6,112
Refined products and renewables			
Refined products sold (barrels)	9,833		9,833

Operating Income (Loss) by Segment

Our operating income (loss) by segment is as follows:

Segment	Year Ended March 31, 2014	2013	Change
		(in thousands)	
Crude oil logistics	$ 678	$ 34,236	$ (33,558)
Water solutions	10,317	8,576	1,741
Liquids	71,888	30,336	41,552
Retail propane	61,285	46,869	14,416
Refined products and renewables	6,514		6,514
Corporate and other	(44,117)	(32,710)	(11,407)
Operating income	$ 106,565	$ 87,307	$ 19,258

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Crude Oil Logistics

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

	Year Ended March 31, 2014	2013 (in thousands)	Change
Revenues:			
Crude oil sales	$ 4,559,923	$ 2,322,706	$ 2,237,217
Crude oil transportation and other	36,469	16,442	20,027
Total revenues (1)	4,596,392	2,339,148	2,257,244
Expenses:			
Cost of sales	4,515,244	2,267,507	2,247,737
Operating expenses	53,872	25,484	28,388
General and administrative expenses	4,487	2,745	1,742
Depreciation and amortization expense	22,111	9,176	12,935
Total expenses	4,595,714	2,304,912	2,290,802
Segment operating income	$ 678	$ 34,236	$ (33,558)

(1) Revenues include $37.8 million and $22.9 million of intersegment sales during the years ended March 31, 2014 and 2013, respectively, that are eliminated in our consolidated statements of operations.

Revenues. Our crude oil logistics segment generated $4.6 billion of revenue from crude oil sales during the year ended March 31, 2014, selling 46.1 million barrels at an average price of $98.90 per barrel. During the year ended March 31, 2013, our crude oil logistics segment generated $2.3 billion of revenue from crude oil sales, selling 24.4 million barrels at an average price of $95.30 per barrel. The increase in volume during the year ended March 31, 2014 compared to the year ended March 31, 2013 was due in part to the fact that we did not own a crude oil logistics business for the full 12 months ended March 31, 2013, as we acquired this business in our June 19, 2012 merger with High Sierra Energy, LP and High Sierra Energy GP, LLC (collectively, High Sierra). The increase in volume was also due to acquisitions of crude oil logistics businesses, including Gavilon Energy, Pecos Gathering & Marketing, L.L.C. and certain of its affiliated companies (collectively, Pecos), and Third Coast Towing, LLC (Third Coast), among others. Of this increase, $1.0 billion was attributable to Gavilon Energy.

Crude oil transportation and other revenues were $36.5 million during the year ended March 31, 2014, compared to $16.4 million of crude oil transportation and other revenues during the year ended March 31, 2013. This increase was due primarily to the fact that we did not own a crude oil logistics business until our June 19, 2012 merger with High Sierra, and was also due in part to acquisitions of crude oil logistics businesses, including Gavilon Energy, Pecos, and Third Coast.

Cost of Sales. Our cost of crude oil sold was $4.5 billion during the year ended March 31, 2014, as we sold 46.1 million barrels at an average cost of $97.93 per barrel. Our cost of sales during the year ended March 31, 2014 was increased by $2.2 million of net unrealized losses on derivatives. During the year ended March 31, 2013, our cost of crude oil was $2.3 billion, as we sold 24.4 million barrels at an average cost of $93.03 per barrel.

Operating Expenses. Our crude oil logistics segment incurred $53.9 million of operating expenses during the year ended March 31, 2014, compared to $25.5 million of operating expenses during the year ended March 31, 2013. This increase was due primarily to the fact that we did not own a crude oil logistics business until our June 19, 2012 merger with High Sierra, and was also due in part to the expansion of operations resulting from acquisitions, including Gavilon Energy, Pecos, and Third Coast. Of this increase, $10.1 million was attributable to Gavilon Energy.

General and Administrative Expenses. Our crude oil logistics segment incurred $4.5 million of general and administrative expenses during the year ended March 31, 2014, compared to $2.7 million of general and administrative expenses during the year ended March 31, 2013. This increase was due primarily to the fact that we did not own a crude oil logistics business until our June 19, 2012 merger with High Sierra, and was also due in part to the expansion of operations resulting from acquisitions. Of this increase, $1.0 million was attributable to our acquisition of Gavilon Energy.

Depreciation and Amortization Expense. Our crude oil logistics segment incurred $22.1 million of depreciation and amortization expense during the year ended March 31, 2014, compared to $9.2 million of depreciation and amortization expense

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during the year ended March 31, 2013. This increase was due primarily to the fact that we did not own a crude oil logistics business until our June 19, 2012 merger with High Sierra, and was also due in part to the expansion of operations resulting from acquisitions. Of this increase, $2.8 million was attributable to our acquisition of Gavilon Energy.

Operating Income. Our crude oil logistics segment generated $0.7 million of operating income during the year ended March 31, 2014, compared to $34.2 million of operating income during the year ended March 31, 2013. Acquisitions of businesses contributed to operating income during the year ended March 31, 2014, although this benefit was offset by several factors. These factors included a narrowing of price differences between markets, which reduced our opportunities to generate increased margins by transporting product from lower-price to higher-price markets, and increased competition in the South Texas region from newly constructed pipelines. Operating income during the year ended March 31, 2014 was reduced by $3.0 million 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, contingent upon the continued service of the employees. We also recorded $0.5 million of employee severance expense during the year ended March 31, 2014 as a result of personnel changes subsequent to the Gavilon Energy acquisition.

Water Solutions

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

	Year Ended March 31,		Change	
	2014	2013	Acquisitions (1)	Other
	(in thousands)			
Revenues:				
Water treatment and disposal	$ 125,788	$ 54,334	$ 64,119	$ 7,335
Water transportation	17,312	7,893	14,231	(4,812)
Total revenues	143,100	62,227	78,350	2,523
Expenses:				
Cost of sales	11,738	5,611	9,325	(3,198)
Operating expenses	62,178	25,452	35,377	1,349
General and administrative expenses	3,762	1,665	1,239	858
Depreciation and amortization expense	55,105	20,923	26,955	7,227
Total expenses	132,783	53,651	72,896	6,236
Segment operating income	$ 10,317	$ 8,576	$ 5,454	$ (3,713)

(1) Represents the change in revenues and expenses attributable to acquisitions subsequent to the merger with High Sierra. The cost of sales amount shown in this column does not include derivative gains and losses, as these cannot be attributed to specific facilities.

Revenues. Our water solutions segment generated $125.8 million of treatment and disposal revenue during the year ended March 31, 2014, taking delivery of 62.8 million barrels of wastewater at an average revenue of $2.00 per barrel. During the year ended March 31, 2013, our water solutions segment generated $54.3 million of treatment and disposal revenue, taking delivery of 25.0 million barrels of wastewater at an average revenue of $2.17 per barrel. The increase in revenues was due primarily to the fact that we did not own a water solutions business until our June 19, 2012 merger with High Sierra and was due also to acquisitions during the year ended March 31, 2013, including Indigo, and acquisitions during the year ended March 31, 2014, including OWL, Big Lake and Coastal. The decrease in revenue per barrel was due primarily to the fact that the expansion of our water solutions business subsequent to our merger with High Sierra has been primarily in Texas, where the market rates for water disposal services are typically lower than in Wyoming or Colorado.

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In our June 2012 merger with High Sierra, we acquired a water transportation business in Oklahoma. In our August 2013 acquisition of OWL, we acquired a water transportation business in Texas. Our water solutions segment generated $17.3 million of transportation revenues during the year ended March 31, 2014, compared to $7.9 million of transportation revenues during the year ended March 31, 2013. This increase was due primarily to the acquisition of OWL. This increase was partially offset by a decrease in water transportation revenues generated by the water solutions business acquired in the merger with High Sierra, which resulted primarily from a slowdown in production activities by a customer. During the three months ended December 31, 2013, we wound down our water transportation operations in Oklahoma, transferring certain of the assets to our business in Texas and selling the remaining assets.

Cost of Sales. The cost of sales for our water solutions segment was $11.7 million during the year ended March 31, 2014. Our cost of sales during the year ended March 31, 2014 was increased by $0.6 million of net unrealized losses on derivatives. Because a portion of our processing revenue is generated from the sale of recovered hydrocarbons, we enter into derivatives to protect against the risk of a decline in the market price of a portion of the hydrocarbons we expect to recover. During the year ended March 31, 2013, the cost of sales for our water solutions segment was $5.6 million. Our cost of sales during the year ended March 31, 2013 was increased by $1.0 million of net unrealized losses on derivatives. The increase in our cost of sales was due primarily to the expansion of our operations through acquisitions of water solutions businesses.

Operating Expenses. Our water solutions segment incurred $62.2 million of operating expenses during the year ended March 31, 2014, compared to $25.5 million of operating expenses during the year ended March 31, 2013. This increase was due primarily to the fact that we did not own a water solutions business until our June 19, 2012 merger with High Sierra, and was also due primarily to subsequent acquisitions of businesses. We incurred losses on disposal of property, plant and equipment of $2.0 million during the year ended March 31, 2014 as a result of property damage from lightning strikes at two of our facilities.

General and Administrative Expenses. Our water solutions segment incurred $3.8 million of general and administrative expenses during the year ended March 31, 2014, compared to $1.7 million of general and administrative expenses during the year ended March 31, 2013. This increase was due in part to the fact that we did not own a water solutions business until our June 19, 2012 merger with High Sierra, and was also due to subsequent acquisitions of businesses.

Depreciation and Amortization Expense. Our water solutions segment incurred $55.1 million of depreciation and amortization expense during the year ended March 31, 2014, compared to $20.9 million of depreciation and amortization expense

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during the year ended March 31, 2013. This increase was due in part to the fact that we did not own a water solutions business until our June 19, 2012 merger with High Sierra, and was also due to subsequent acquisitions of businesses. The increase is also due in part to $2.1 million of amortization expense related to trade name intangible assets. During the year ended March 31, 2014, we ceased using certain trade names and began amortizing them as finite-lived defensive assets.

Operating Income. Our water solutions segment generated $10.3 million of operating income during the year ended March 31, 2014, compared to operating income of $8.6 million during the year ended March 31, 2013. Exclusive of acquisitions during the year ended March 31, 2014, our operating income decreased by $3.7 million. Increases in revenues were offset by increases in operating expenses, including a $7.2 million increase in depreciation and amortization expense. The businesses acquired during the year ended March 31, 2014 generated operating income of $5.5 million, which included $27.0 million of depreciation and amortization expense, which consisted primarily of amortization expense on acquired customer relationship intangible assets.

Liquids

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

	Year Ended March 31, 2014	2013	Change
		(in thousands)	
Revenues:			
Propane sales	$ 1,632,948	$ 841,448	$ 791,500
Other product sales	1,231,965	858,276	373,689
Other revenues	31,062	33,954	(2,892)
Total revenues (1)	2,895,975	1,733,678	1,162,297
Expenses:			
Cost of sales - propane	1,559,266	801,694	757,572
Cost of sales - other products	1,179,944	836,747	343,197
Cost of sales - other	24,439	20,950	3,489
Operating expenses	42,977	27,605	15,372
General and administrative expenses	6,443	5,261	1,182
Depreciation and amortization expense	11,018	11,085	(67)
Total expenses	2,824,087	1,703,342	1,120,745
Segment operating income	$ 71,888	$ 30,336	$ 41,552

(1) Revenues include $245.6 million and $128.9 million of intersegment sales during the years ended March 31, 2014 and 2013, respectively, that are eliminated in our consolidated statements of operations.

Revenues. Our liquids segment generated $1.6 billion of wholesale propane sales revenue during the year ended March 31, 2014, selling 1.2 billion gallons at an average price of $1.37 per gallon. During the year ended March 31, 2013, our liquids segment generated $841.4 million of wholesale propane sales revenue, selling 912.6 million gallons at an average price of $0.92 per gallon. Approximately 221.2 million gallons of the increase in volumes was due to the fact that we only owned the natural gas liquids business of High Sierra for a part of the year ended March 31, 2013. The remaining increase in volume was due to several factors, including higher market demand, due in part to colder weather conditions, and the expansion of our customer base. In addition, during the year ended March 31, 2013, we upgraded two terminals that we acquired in February 2012, which enabled us to expand our wholesale operations from these terminals.

Our liquids segment generated $1.2 billion of other wholesale products sales revenue during the year ended March 31, 2014, selling 786.7 million gallons at an average price of $1.57 per gallon. During the year ended March 31, 2013, our liquids segment generated $858.3 million of other wholesale products sales revenue, selling 505.5 million gallons at an average price of $1.70 per gallon. Approximately 454.1 million gallons of the increase in volumes was due to the fact that we only owned the natural gas liquids business of High Sierra for a part of the year ended March 31, 2013. The remaining increase in volume was due to several factors, including higher market demand for butane to be used in gasoline blending operations, the expansion of our customer base, and an increased focus on the opportunity to more fully utilize our terminals to market butane.

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Cost of Sales. Our cost of wholesale propane sales was $1.6 billion during the year ended March 31, 2014, as we sold 1.2 billion gallons at an average cost of $1.31 per gallon. 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. During the year ended March 31, 2013, our cost of wholesale propane sales was $801.7 million, as we sold 912.6 million gallons at an average cost of $0.88 per gallon. Our cost of wholesale propane sales during the year ended March 31, 2013 was reduced by $3.2 million of net unrealized gains on derivatives.

Declining wholesale propane prices during the first quarter of the prior fiscal year had an adverse effect on cost of sales during the year ended March 31, 2013. Our wholesale segment utilizes a weighted-average inventory costing method to calculate cost of sales. Propane prices decreased steadily during April and May 2012, as a result of which the replacement cost of propane was at times lower than the weighted-average cost, which had an adverse effect on margins. 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 the 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, such as we experienced during the three months ended June 30, 2012, this can result in negative margins on these sales, which we recovered when delivering future volumes.

Our cost of sales of other products was $1.2 billion during the year ended March 31, 2014, as we sold 786.7 million gallons at an average cost of $1.50 per gallon. 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. During the year ended March 31, 2013, our cost of sales of other products was $836.7 million, as we sold 505.5 million gallons at an average cost of $1.66 per gallon. Our cost of sales of other products during the year ended March 31, 2013 was increased by $7.5 million of net unrealized losses on derivatives.

Operating Expenses. Our liquids segment incurred $43.0 million of operating expenses during the year ended March 31, 2014, compared to $27.6 million of operating expenses during the year ended March 31, 2013. This increase was due primarily to expanded operations. In addition, during the year ended March 31, 2014, we recorded an impairment of $5.3 million related to the property, plant and equipment of one of our terminals.

General and Administrative Expenses. Our liquids segment incurred $6.4 million of general and administrative expenses during the year ended March 31, 2014, compared to $5.3 million of general and administrative expenses during the year ended March 31, 2013. This increase was due primarily to expanded operations.

Depreciation and Amortization Expense. Our liquids segment incurred $11.0 million of depreciation and amortization expense during the year ended March 31, 2014, compared to $11.1 million of depreciation and amortization expense during the year ended March 31, 2013.

Operating Income. Our liquids segment generated $71.9 million of operating income during the year ended March 31, 2014, compared to $30.3 million of operating income during the year ended March 31, 2013. The increase in operating income was due primarily to the expansion of our operations and to colder weather conditions. As a result of the cold weather conditions, the demand for natural gas liquids increased considerably during the recent winter, which had a favorable impact on our sales volumes. The demand also resulted in increases to the market prices for natural gas liquids, which had a favorable impact on product margins, as we purchased inventory when prices, and therefore our average cost of inventory, were lower than when we sold the inventory. These increases were partially offset by increased operating expenses as a result of expanding our operations. During the year ended March 31, 2014, operating income was increased by $4.2 million of net unrealized gains on derivatives. During the year ended March 31, 2013, operating income was reduced by $4.3 million of net unrealized losses on derivatives.

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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, 2014	2013	Change
		(in thousands)	
Revenues:			
Propane sales	$ 388,225	$ 288,410	$ 99,815
Distillate sales	127,672	106,192	21,480
Other revenues	35,918	35,856	62
Total revenues	551,815	430,458	121,357
Expenses:			
Cost of sales - propane	233,110	155,118	77,992
Cost of sales - distillates	109,058	90,772	18,286
Cost of sales - other	11,531	12,688	(1,157)
Operating expenses	96,936	88,651	8,285
General and administrative expenses	11,017	10,864	153
Depreciation and amortization expense	28,878	25,496	3,382
Total expenses	490,530	383,589	106,941
Segment operating income	$ 61,285	$ 46,869	$ 14,416

Revenues. Our retail propane segment generated revenue of $388.2 million from propane sales during the year ended March 31, 2014, selling 162.4 million gallons at an average price of $2.39 per gallon. During the year ended March 31, 2013, our retail propane segment generated $288.4 million of revenue from propane sales, selling 144.4 million gallons at an average price of $2.00 per gallon. The increase in volumes and average sales prices during the year ended March 31, 2014 compared to the year ended March 31, 2013 was due primarily to market demand being higher as a result of colder weather conditions. Revenues also benefitted from the continued integration of previously acquired businesses.

Our retail propane segment generated revenue of $127.7 million from distillate sales during the year ended March 31, 2014, selling 35.0 million gallons at an average price of $3.65 per gallon. During the year ended March 31, 2013, our retail propane segment generated $106.2 million of revenue from distillate sales, selling 28.9 million gallons at an average price of $3.68 per gallon. The increase in volumes was due primarily to colder weather conditions and to the acquisitions of smaller retailers.

Cost of Sales. Our cost of retail propane sales was $233.1 million during the year ended March 31, 2014, as we sold 162.4 million gallons at an average cost of $1.44 per gallon. During the year ended March 31, 2013, our cost of retail propane sales was $155.1 million, as we sold 144.4 million gallons at an average cost of $1.07 per gallon.

Our cost of distillate sales was $109.1 million during the year ended March 31, 2014, as we sold 35.0 million gallons at an average cost of $3.12 per gallon. During the year ended March 31, 2013, our cost of distillate sales was $90.8 million, as we sold 28.9 million gallons at an average cost of $3.15 per gallon.

Operating Expenses. Our retail propane segment incurred $96.9 million of operating expenses during the year ended March 31, 2014, compared to $88.7 million of operating expenses during the year ended March 31, 2013. This increase was due in part to the inclusion of Downeast Energy Corp. in our results of operations for the full 12 months ended March 31, 2014, as compared to only 11 of the months in the 12-month period ended March 31, 2013.

General and Administrative Expenses. Our retail propane segment incurred $11.0 million of general and administrative expenses during the year ended March 31, 2014, compared to $10.9 million of general and administrative expenses during the year ended March 31, 2013. This increase was due primarily to acquisitions of smaller retailers.

Depreciation and Amortization Expense. Our retail propane segment incurred $28.9 million of depreciation and amortization expense during the year ended March 31, 2014, compared to $25.5 million of depreciation and amortization expense during the year ended March 31, 2013. This increase was due primarily to capital expenditures and acquisitions.

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Operating Income. Our retail propane segment generated $61.3 million of operating income during the year ended March 31, 2014, compared to $46.9 million of operating income during the year ended March 31, 2013. The increase in operating income was due primarily to increased market demand due to colder weather conditions, partially offset by increased operating expenses.

Refined Products and Renewables

The following table summarizes the operating results of our refined products and renewables segment for the year ended March 31, 2014 (in thousands). Our refined products and renewables segment began with our December 2013 acquisition of Gavilon Energy.

Revenues:		
Refined products sales	$	1,180,895
Renewables sales		176,781
Total revenues		1,357,676
Expenses:		
Cost of sales - refined products		1,172,754
Cost of sales - renewables		171,422
Operating expenses		6,205
General and administrative expenses		156
Depreciation and amortization expense		625
Total expenses		1,351,162
Segment operating income	$	6,514

Revenues. Our refined products sales revenue was $1.2 billion during the year ended March 31, 2014, selling 9.8 million barrels at an average price of $120.10 per barrel. Our renewables sales revenue was $176.8 million during the year ended March 31, 2014.

Cost of Sales. Our cost of refined products sales was $1.2 billion during the year ended March 31, 2014, as we sold 9.8 million barrels at an average cost of $119.27 per barrel. Our cost of renewables sales was $171.4 million during the year ended March 31, 2014.

Operating Expenses. Our refined products and renewables segment incurred $6.2 million of operating expenses during the year ended March 31, 2014.

General and Administrative Expenses. Our refined products and renewables segment incurred $0.2 million of general and administrative expenses during the year ended March 31, 2014.

Depreciation and Amortization Expense. Our refined products and renewables segment incurred $0.6 million of depreciation and amortization expense during the year ended March 31, 2014.

Operating Income. Our refined products and renewables segment generated $6.5 million of operating income during the year ended March 31, 2014.

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Corporate and Other

The operating loss within corporate and other includes the following components:

	Year Ended March 31, 2014	2013	Change
	(in thousands)		
Compressor leasing business (1)	$ 2,336	$ (1)	$ 2,337
Natural gas business (2)	1,363		1,363
Equity-based compensation expense	(17,804)	(10,138)	(7,666)
Acquisition expenses	(6,908)	(5,602)	(1,306)
Other corporate expenses	(23,104)	(16,969)	(6,135)
Total	$ (44,117)	$ (32,710)	$ (11,407)

(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 during the year ended March 31, 2014 was due in part to the timing of award grants and is also due in part to an increase in the market value of our common units. The first restricted units were granted during fiscal year 2013, and therefore were not in existence for the full fiscal year. The life-to-date expense for unvested units is adjusted based on the market value of the common units on the reporting date, and the value of the common units was higher at March 31, 2014 than at March 31, 2013.

The increase in other corporate expenses during the year ended March 31, 2014 was due primarily to increases 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.

Operating income during the year ended March 31, 2014 was reduced by $2.0 million 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, contingent upon the continued service of the employees. We also recorded $2.2 million of employee severance expense during the year ended March 31, 2014 as a result of personnel changes subsequent to the Gavilon Energy acquisition, $1.3 million of which is reported under natural gas business in the table above and the remainder of which is reported under other corporate expenses in the table above.

Other Income, Net

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 which the producers paid us a specified amount in March 2015 and committed to pay us specified additional amounts over a period of 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 in our consolidated statement of operations, net of certain project abandonment costs.

During the year ended March 31, 2015, we settled two separate contractual disputes and recorded $5.5 million of proceeds to other income in our consolidated statement of operations. 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.

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Interest Expense

The largest components of interest expense during the years ended March 31, 2015, 2014 and 2013 have been interest on our Revolving Credit Facility, the 2019 Notes, the 2021 Notes, the 2022 Notes, and the TLP Credit Facility (each as hereinafter defined). See Note 8 to our consolidated financial statements included in this Annual Report for additional information on our long-term debt. The change in interest expense during the periods presented was due primarily to fluctuations in the average outstanding debt balance and the applicable interest rates, as summarized below:

	Revolving Credit Facilities		2019 Notes		2021 Notes		2022 Notes		TLP Credit Facility	
Year Ended March 31,	Average Balance Outstanding (in thousands)	Average Interest Rate	Average Balance Outstanding (in thousands)	Interest Rate	Average Balance Outstanding (in thousands)	Interest Rate	Average Balance Outstanding (in thousands)	Interest Rate	Average Balance Outstanding (in thousands)	Interest Rate
2015	$ 1,172,429	2.35%	$ 400,000	5.13%	$ 450,000	6.88%	$ 250,000	6.65%	$ 250,346	2.10%
2014	588,375	3.04%			205,890	6.88%	250,000	6.65%		
2013	405,114	3.56%					195,890	6.65%		

Interest expense also includes amortization of debt issuance costs, letter of credit fees, interest on equipment financing notes, and accretion of interest on noninterest bearing debt obligations assumed in business combinations.

On June 19, 2012, we made a principal payment of $306.8 million to retire a then-existing revolving credit facility. Upon retirement of this facility, we wrote off the portion of the debt issuance cost intangible asset that had not yet been amortized. This expense is reported as Loss on early extinguishment of debt in our consolidated statement of operations for the year ended March 31, 2013.

The increased level of debt outstanding from fiscal years 2013 to 2015 was due primarily to borrowings to finance acquisitions and capital expenditures.

Income Tax Provision (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.

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. 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 $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 and certain of its subsidiaries were subject to United States federal and state income taxes. On December 31, 2014, we converted these subsidiaries from taxable corporations to non-taxable limited liability companies.

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 $13.2 million during the year ended March 31, 2015, compared to $1.1 million during the year ended March 31, 2014. The increase was due primarily to the July 2014 acquisition of TransMontaigne, in which we acquired a 19.7% limited partner interest in TLP.

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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.

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. Our cash flows from operations are discussed below.

Our borrowing needs vary during the year due 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. TLP s partnership agreement also requires that, within 45 days after the end of each quarter it distribute all of its available cash (as defined in its partnership agreement) to its unitholders as of the record date.

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. 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 continue to pursue a strategy of growth through acquisitions. We expect to consider financing future acquisitions through a variety of sources, including the use of available capacity on our Revolving Credit Facility, the issuance of common units to sellers of businesses we acquire, private placements of common units or debt securities, and public offerings of common units or debt securities. Our ability to raise additional capital through the issuance of debt or equity securities will have a significant impact on our ability to continue to pursue our growth strategy.

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, 2015, our Revolving Credit Facility had a total capacity of $2.296 billion.

The Expansion Capital Facility had a total capacity of $858.0 million for cash borrowings at March 31, 2015. At that date, we had outstanding borrowings of $702.5 million on the Expansion Capital Facility. The Working Capital Facility had a total capacity of $1.438 billion for cash borrowings and letters of credit at March 31, 2015. At that date, we had outstanding borrowings of $688.0 million and outstanding letters of credit of $108.6 million on 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.

All borrowings under the Credit Agreement bear interest, at our option, at (i) an alternate base rate plus a margin of 0.50% to 1.50% per annum or (ii) an adjusted LIBOR rate plus a margin of 1.50% to 2.50% per annum. The applicable margin is determined based on our consolidated leverage ratio, as defined in the Credit Agreement. At March 31, 2015, all borrowings under the Credit Agreement were LIBOR borrowings with an interest rate at March 31, 2015 of 2.18%, calculated as the LIBOR rate of 0.18% plus a margin of 2.0%. At March 31, 2015, the interest rate in effect on letters of credit was 2.25%. Commitment fees are charged at a rate ranging from 0.38% to 0.50% on any unused capacity.

The Credit Agreement is secured by substantially all of our assets. The Credit Agreement specifies that our leverage ratio, as defined in the Credit Agreement, cannot exceed 4.25 to 1 at any quarter end. The leverage coverage ratio in our Credit Agreement excludes TLP s debt. At March 31, 2015, our leverage ratio was approximately 3.2 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, 2015, our interest coverage ratio was approximately 5.9 to 1.

The Credit Agreement contains various customary representations, warranties, and additional covenants, including, without limitation, limitations on fundamental changes and limitations on indebtedness and liens. Our obligations under the Credit Agreement may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) a breach by the Partnership or its subsidiaries of any material representation or warranty or any covenant made in the Credit Agreement, or (iii) certain events of bankruptcy or insolvency.

At March 31, 2015, 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. We received net proceeds of $393.5 million, after the initial purchasers discount of $6.0 million and offering costs of $0.5 million. We used the net proceeds to reduce the outstanding balance on our Revolving Credit Facility.

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 prior to the maturity date, although we would be required to pay a premium price for early redemption.

The Partnership and NGL Energy Finance Corp. are co-issuers of the 2019 Notes, and the obligations under the 2019 Notes are guaranteed by certain of our existing and future restricted subsidiaries that incur or guarantee indebtedness under certain of our other indebtedness, including the Revolving Credit Facility. The indenture governing the 2019 Notes contains various customary covenants, including, without limitation, limitations on fundamental changes and limitations on indebtedness and liens. Our obligations under the indenture may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) experiencing an event of default on certain other debt agreements, or (iii) certain events of bankruptcy or insolvency.

At March 31, 2015, we were in compliance with the covenants under the indenture governing the 2019 Notes.

We also entered into a registration rights agreement whereby, in February 2015, we exchanged the 2019 Notes for a new issue of notes registered under the Securities Act that has substantially identical terms to 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. We received net proceeds of $438.4 million, after the initial purchasers discount of $10.1 million and offering costs of $1.5 million. We used the net proceeds to reduce the outstanding balance on our Revolving Credit Facility.

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 prior to the maturity date, although we would be required to pay a premium for early redemption.

The Partnership and NGL Energy Finance Corp. are co-issuers of the 2021 Notes, and the obligations under the 2021 Notes are guaranteed by certain of our existing and future restricted subsidiaries that incur or guarantee indebtedness under certain of our other indebtedness, including the Revolving Credit Facility. The indenture governing the 2021 Notes contains various customary covenants, including, without limitation, limitations on fundamental changes and limitations on indebtedness and liens. Our obligations under the indenture may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) experiencing an event of default on certain other debt agreements, or (iii) certain events of bankruptcy or insolvency.

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At March 31, 2015, we were in compliance with the covenants under the indenture governing the 2021 Notes.

We also entered into a registration rights agreement whereby, in February 2015, we exchanged the 2021 Notes for a new issue of notes registered under the Securities Act that has substantially identical terms to 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. 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.

The Note Purchase Agreement contains various customary representations, warranties, and additional covenants that, among other things, limit our ability to (subject to certain exceptions): (i) incur additional debt, (ii) pay dividends and make other restricted payments, (iii) create or permit certain liens, (iv) create or permit restrictions on the ability of certain of our subsidiaries to pay dividends or make other distributions to us, (v) enter into transactions with affiliates, (vi) enter into sale and leaseback transactions and (vii) consolidate or merge or sell all or substantially all or any portion of our assets. In addition, the Note Purchase Agreement contains similar leverage ratio and interest coverage ratio requirements to those of our Credit Agreement, which is described above.

The Note Purchase Agreement provides for customary events of default that include, among other things (subject in certain cases to customary grace and cure periods): (i) nonpayment of principal or interest, (ii) breach of certain covenants contained in the Note Purchase Agreement or the 2022 Notes, (iii) failure to pay certain other indebtedness or the acceleration of certain other indebtedness prior to maturity if the total amount of such indebtedness unpaid or accelerated exceeds $10.0 million, (iv) the rendering of a judgment for the payment of money in excess of $10.0 million, (v) the failure of the Note Purchase Agreement, the 2022 Notes, or the guarantees by the subsidiary guarantors to be in full force and effect in all material respects and (vi) certain events of bankruptcy or insolvency. Generally, if an event of default occurs (subject to certain exceptions), the trustee or the holders of at least 51% in aggregate principal amount of the then outstanding 2022 Notes of any series may declare all of the 2022 Notes of such series to be due and payable immediately.

At March 31, 2015, we were in compliance with the covenants under the Note Purchase Agreement.

TLP Credit Facility

TLP is party to a credit agreement with a syndicate of banks that provides for a revolving credit facility (the TLP Credit Facility). The TLP Credit Facility provides for a maximum borrowing line of credit equal to the lesser of (i) $400 million and (ii) 4.75 times Consolidated EBITDA (as defined: $368.7 million at March 31, 2015). The terms of the TLP Credit Facility include covenants that restrict TLP s ability to make cash distributions, acquisitions and investments, including investments in joint ventures. TLP may make distributions of cash to the extent of TLP s available cash as defined in TLP s partnership agreement. TLP may make acquisitions and investments that meet the definition of permitted acquisitions ; other investments which may not exceed 5% of consolidated net tangible assets ; and additional future permitted JV investments up to $125 million, which may include additional investments in BOSTCO. The principal balance of loans and any accrued and unpaid interest are due and payable in full on the maturity date of July 31, 2018.

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The following table summarizes our basis in the assets and liabilities of TLP at March 31, 2015, inclusive of the impact of our acquisition accounting for the business combination with TransMontaigne (in thousands):

Cash and cash equivalents	$	918
Accounts receivable - trade		9,069
Accounts receivable - affiliates		583
Inventories		1,361
Prepaid expenses and other current assets		1,410
Property, plant and equipment, net		475,506
Goodwill		28,074
Intangible assets, net		72,295
Investments in unconsolidated entities		255,073
Other noncurrent assets		2,458
Accounts payable - trade		(6,565)
Accounts payable - affiliates		(76)
Net intercompany payable		(1,965)
Accrued expenses and other payables		(8,715)
Advance payments received from customers		(146)
Long-term debt		(250,000)
Other noncurrent liabilities		(3,541)
Net assets	$	575,739

TLP may elect to have loans under the TLP Credit Facility bear interest either (i) at a rate of LIBOR plus a margin ranging from 2% to 3% depending on the total leverage ratio then in effect, or (ii) at the base rate plus a margin ranging from 1% to 2% depending on the total leverage ratio then in effect. TLP also pays a commitment fee on the unused amount of commitments, ranging from 0.375% to 0.5% per annum, depending on the total leverage ratio then in effect. For the period from July 1, 2014 to March 31, 2015, the weighted-average interest rate on borrowings under the TLP Credit Facility was approximately 2.10%. TLP s obligations under the TLP Credit Facility are secured by a first priority security interest in favor of the lenders in the majority of TLP s assets, including TLP s investments in unconsolidated affiliates. At March 31, 2015, TLP had outstanding borrowings under the TLP Credit Facility of $250 million and no outstanding letters of credit.

The TLP Credit Facility also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the TLP Credit Facility are (i) a total leverage ratio test (not to exceed 4.75 times), (ii) a senior secured leverage ratio test (not to exceed 3.75 times) in the event TLP issues senior unsecured notes, and (iii) a minimum interest coverage ratio test (not less than 3.0 times). These financial covenants are based on a defined financial performance measure within the TLP Credit Facility known as Consolidated EBITDA.

TLP s Credit Facility is non-recourse to NGL.

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Revolving Credit Balances

The following table summarizes our revolving credit facility borrowings:

	Average Balance Outstanding	Lowest Balance (in thousands)	Highest Balance
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
Year Ended March 31, 2014:			
Expansion capital borrowings	$ 392,822	$	$ 546,000
Working capital borrowings	195,553		448,500

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:

Cash Flows Provided by (Used in):	**2015**	**Year Ended March 31, 2014 (in thousands)**	**2013**
Operating activities, before changes in operating assets and liabilities	$ 99,290	$ 243,303	$ 146,395
Changes in operating assets and liabilities	163,104	(158,067)	(13,761)
Operating activities	$ 262,394	$ 85,236	$ 132,634
Investing activities	(1,366,221)	(1,455,373)	(546,621)
Financing activities	1,134,690	1,369,016	417,716

Operating Activities. The growth in our operating cash flows from fiscal years 2013 through 2015 was driven primarily by increased operating activity resulting from acquisitions. Changes in working capital due to changes in the timing of cash receipts and payments can have a significant impact on cash flows from operations. During fiscal years 2013 through 2015, our cash outflows from investing activities included the purchase of working capital in business combinations, a portion of which has benefitted (or will benefit) cash flows from operations as the working capital is recovered.

The seasonality of our natural gas liquids businesses has a significant effect on our cash flows from operating activities. The changes in our operating assets and liabilities caused by the seasonality of our retail and wholesale natural gas liquids businesses also have a significant impact 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

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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 $1.4 billion during the year ended March 31, 2015, compared to $1.5 billion in net cash used in investing activities during the year ended March 31, 2014. 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 the proceeds from derivatives.

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

- a $310.0 million increase due to 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;

- a $38.6 million increase in capital expenditures during the year ended March 31, 2015, of which $30.1 million represented expansion capital and $8.5 million represented maintenance capital (of this maintenance capital, $7.9 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.

Net cash used in investing activities was $1.5 billion during the year ended March 31, 2014, compared to $546.6 million in net cash used in investing activities during the year ended March 31, 2013. The increase in net cash used in investing activities was due primarily to:

- a $778.0 million increase in cash paid for acquisitions during the year ended March 31, 2014 due primarily to our December 2013 acquisition of Gavilon Energy;

- a $92.7 million increase in capital expenditures during the year ended March 31, 2014, of which $74.3 million represented expansion capital and $18.4 million represented maintenance capital; and

- a $47.5 million increase in investing cash outflows from commodity derivatives during the year ended March 31, 2014.

Financing Activities. Net cash provided by financing activities was $1.1 billion during the year ended March 31, 2015, compared to $1.4 billion in net cash provided by financing activities during the year ended March 31, 2014. 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;

- 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,

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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.

Net cash provided by financing activities was $1.4 billion during the year ended March 31, 2014, compared to $417.7 million in net cash provided by financing activities during the year ended March 31, 2013. The increase in net cash provided by financing activities was due primarily to:

- a $650.8 million increase in the proceeds received from the sale of our common units during the year ended March 31, 2014 to fund acquisitions;

- a $200.0 million increase in the proceeds received from debt issuances during the years ended March 31, 2014 and 2013; and

- a $181.0 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, 2014.

These increases in net cash provided by financing activities were partially offset by a $74.3 million increase in distributions paid to our partners and noncontrolling interest owners during the year ended March 31, 2014.

The following table summarizes the distributions declared subsequent to our IPO:

Date Declared	Record Date	Date Paid	Amount Per Unit	Amount Paid To Limited Partners (in thousands)	Amount Paid To General Partner (in thousands)
July 25, 2011	August 3, 2011	August 12, 2011	$ 0.1669	$ 2,467	$ 3
October 21, 2011	October 31, 2011	November 14, 2011	0.3375	4,990	5
January 24, 2012	February 3, 2012	February 14, 2012	0.3500	7,735	10
April 19, 2012	April 30, 2012	May 15, 2012	0.3625	9,165	10
July 24, 2012	August 3, 2012	August 14, 2012	0.4125	13,574	134
October 17, 2012	October 29, 2012	November 14, 2012	0.4500	22,846	707
January 24, 2013	February 4, 2013	February 14, 2013	0.4625	24,245	927
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

The following table summarizes the distributions declared by TLP subsequent to 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):

Date Declared	Record Date	Date Paid	Amount Per Unit	Amount Paid To NGL (in thousands)	Amount Paid To Other Partners (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

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Contractual Obligations

The following table summarizes our contractual obligations at March 31, 2015 for our fiscal years ending thereafter:

	Total	2016	2017	Years Ending March 31, 2018 (in thousands)	2019	2020	Thereafter
Principal payments on long-term debt							
Expansion capital borrowings	$ 702,500	$	$	$	$ 702,500	$	$
Working capital borrowings	688,000				688,000		
2019 Notes	400,000					400,000	
2021 Notes	450,000						450,000
2022 Notes	250,000			25,000	50,000	50,000	125,000
TLP Credit Facility	250,000				250,000		
Other long-term debt	9,271	4,473	2,567	1,626	362	105	138
Interest payments on long-term debt							
Revolving Credit Facility (1)	128,678	35,744	35,744	35,744	21,446		
2019 Notes	92,250	20,500	20,500	20,500	20,500	10,250	
2021 Notes (2)	217,013	31,388	30,938	30,938	30,938	30,938	61,873
2022 Notes	83,125	16,625	16,625	16,209	13,300	9,975	10,391
TLP Credit Facility	22,256	6,675	6,675	6,675	2,231		
Other long-term debt	438	203	123	76	18	9	9
Letters of credit	108,584				108,584		
Future minimum lease payments under other noncancelable operating leases	541,845	119,817	102,394	87,302	63,205	53,423	115,704
Future minimum throughput payments under noncancelable agreements (3)	511,708	122,052	81,935	82,016	81,222	53,511	90,972
Construction commitments (4)	666,497	426,384	240,113				
Fixed-price commodity purchase commitments	35,476	35,476					
Index-price commodity purchase commitments (5)	728,262	728,262					
Total contractual obligations	$ 5,885,903	$ 1,547,599	$ 537,614	$ 306,086	$ 2,032,306	$ 608,211	$ 854,087
Purchase commitments (thousands):							
Natural gas liquids fixed-price (gallons) (6)	57,792	57,792					
Natural gas liquids index-price (gallons) (6)	659,603	659,603					
Crude oil index-price (barrels) (6)	8,450	8,450					

(1) The estimated interest payments on our Revolving Credit Facility are based on principal and letters of credit outstanding at March 31, 2015. See Note 8 to our consolidated financial statements included in this Annual Report for additional information on our Credit Agreement.

(2) Interest payments for the fiscal year ending March 31, 2016 include $0.5 million of liquidated damages resulting from a delay in completing an exchange offer.

(3) At March 31, 2015, we had agreements with crude oil and refined products pipeline operators obligating us to minimum throughput payments in exchange for pipeline capacity commitments.

(4) At March 31, 2015, we had the following construction commitments:

- As described in Recent Developments, Grand Mesa completed a successful open season in which it received the requisite support, in the form of ship-or-pay volume commitments from multiple shippers, to begin construction of a 20-inch pipeline system. The estimated construction cost of Grand Mesa is $655.0 million and we anticipate that the pipeline will commence service in the second half of calendar year 2016.

- In February 2015, we acquired Sawtooth NGL Caverns, LLC, which owns a natural gas liquids salt dome storage facility in Utah with rail and truck access to western U.S. markets. As part of this acquisition, we also entered into a construction agreement to expand the storage capacity of the facility by constructing two additional salt dome storage facilities. The estimated construction cost of this expansion is $41.2 million and we anticipate this project will be completed by the end of calendar year 2015.

- In March 2015, we entered into an agreement with a third party to construct a solids processing facility and solids disposal facility in Weld County, Colorado. Our estimated construction cost for this project is $9.0 million. We anticipate that these facilities will be completed in the second half of calendar year 2016.

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(5) At March 31, 2015, we had the following purchase commitments (in thousands):

Natural gas liquids index-price	$	352,563
Crude oil index-price		375,699

Index prices are based on a forward price curve at March 31, 2015. A theoretical change of $0.10 per gallon in the underlying commodity price at March 31, 2015 would result in a change of $66.0 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, 2015 would result in a change of $8.5 million in the value of our index-price crude oil purchase commitments.

(6) At March 31, 2015, we had the following sales contract volumes (in thousands):

Natural gas liquids fixed-price (gallons)	104,153
Natural gas liquids index-price (gallons)	223,234
Crude oil fixed-price (barrels)	1,580
Crude oil index-price (barrels)	6,684

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.

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 nine months ended March 31, 2015 (the spot price for NYMEX West Texas Intermediate crude oil at Cushing, Oklahoma declined from $105.34 per barrel at July 1, 2014 to $47.60 per barrel at March 31, 2015). 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.

As of March 31, 2015, crude oil markets were in contango (a condition in which the forward crude price is greater than the spot price). During most of the last two years, crude oil markets were backwardated (a condition in which the forward crude oil price is lower than the spot price). 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.

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 during the year ended March 31, 2015. At current market prices, producers may reduce drilling activity, which could have an adverse impact on the volumes of our water solutions business.

A portion of the revenues of our water solutions business are generated from the sale of crude oil that we recover in the process of treating the wastewater. Because of this, lower crude prices result in lower per barrel revenues for our water solutions business.

Recent Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. ASU No. 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The ASU is effective for the Partnership for both annual and interim periods beginning April 1, 2016 and requires retrospective application for all prior periods presented. Early adoption of this ASU is permitted for financial statements that have not been previously issued. We plan to adopt this ASU effective March 31, 2016, at which time we will begin presenting debt issuance costs as a reduction to long-term debt, rather than as an intangible asset.

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In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers. ASU No. 2014-09 will replace most existing revenue recognition guidance in GAAP. The core principle of this ASU is that an entity should recognize revenue for the transfer of goods or services equal to the amount that it expects to be entitled to receive for those goods or services. The ASU is effective for the Partnership beginning April 1, 2017, and allows for both full retrospective and modified retrospective (with cumulative effect) methods of adoption. We are in the process of determining the method of adoption and assessing the impact of this ASU on our consolidated financial statements.

Critical Accounting Policies

The preparation of financial statements and related disclosures in compliance 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 financial condition 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 revenues from product sales at the time title to the product transfers to the purchaser, which typically occurs upon receipt of the product by the purchaser. We record terminaling, transportation, storage and service revenues at the time the service is performed, and we record tank and other rentals over the term of the lease. Pursuant to terminaling services agreements with certain of our throughput customers, we are entitled to the volume of product gained resulting from differences in the measurement of product volumes received and distributed at our terminaling facilities. Such measurement differentials occur as the result of the inherent variances in measurement devices and methodology. We recognize as revenue the net proceeds from the sale of the product gained. Revenues for our water solutions segment are recognized upon receipt of 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. Amounts billed to customers for shipping and handling costs are included 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 concurrently and are entered into in contemplation of each other, we record the revenues for these transactions net of cost of sales.

Impairment of Long-Lived Assets

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. We concluded that each of our operating segments represented one reporting unit. Our operating segments, and the reportable segments within which they are included, are listed below:

Operating Segment	**Reportable Segment**
Crude Oil Logistics	Crude Oil Logistics
Water Solutions	Water Solutions
Liquids Tulsa-based Operations	Liquids
Liquids Denver-based Operations	Liquids
Retail East	Retail Propane
Retail West	Retail Propane
Refined Products and Renewables	Refined Products and Renewables

Our first step in performing the annual goodwill impairment analysis is to perform a qualitative assessment of each reporting unit to assess whether it is more likely than not that the fair value of each reporting unit is greater than the book value of the reporting unit. For the crude oil logistics, liquids, retail, and refined products and renewables segments, our qualitative assessments indicated that it was more likely than not that the fair values for each of these reporting units exceeded their book values, and therefore no further impairment testing was required. In preparing this analysis, we considered market conditions in our liquids, retail, and refined products and renewables businesses, which have remained stable, our historic operating results, and our long-term expectations for

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these reporting units. We also considered that although a sharp decline in crude oil prices during the second half of calendar year 2014 had an adverse impact on our crude oil logistics segment gross margin and operating results, by January 1, 2015 crude oil forward prices were in contango (a condition in which forward prices are higher than spot prices), which we expect will benefit the profitability of the crude oil logistics reporting unit, as it enables us to realize increased revenues and margin from our crude oil terminal storage assets. We also considered margins and operating results related to our Grand Mesa crude oil pipeline, which has ship-or-pay volume commitments from multiple shippers and is currently under construction and expected to commence service in the second half of calendar year 2016.

Because a significant component of our water solutions revenue and operating results is determined by the price at which we are able to sell crude oil condensate that is recovered from the disposal water and solids delivered to our disposal sites, and crude oil prices declined significantly during the second half of calendar year 2014, we performed a quantitative goodwill impairment assessment for our water solutions reporting unit.

We performed our goodwill impairment test and estimated the fair value of our water solutions reporting unit based on the income approach, also known as the discounted cash flow method which utilizes the present value of cash flows to estimate the fair value. The future cash flows of our water solutions reporting unit were projected based upon estimates as of the test date of future revenues, operating expenses and cash outflows necessary to support these cash flows, including working capital and maintenance capital expenditures. We also considered expectations regarding expected disposal volumes, which have continued in spite of the lower crude oil price environment as oilfield producers have focused on their most productive properties and have continued to deliver disposal volumes to our facilities, and the crude oil pricing environment as reflected in crude oil forward prices as of the test date. In performing the discounted cash flow analysis, we utilized our internal fiscal year 2016 cash flow projections prepared as part of our annual budgeting process. Consistent with observed disposal volume trends, the budgeted disposal volumes were based on an expectation that existing crude oil and natural gas production by our customers will continue, with limited disposal volume growth from development of new producing wells by our customers. For fiscal years 2016 to 2020, we projected the selling price of recovered crude oil based on crude oil forward prices as of our test date, January 1, 2015. For other operating income and expenses for years beyond fiscal year 2016, we assumed a 2% long-term growth rate in operating income, which is lower than our long-term expectations and our actual historic growth rate, and reflects our expectation for long-term growth in oilfield production and long-term inflation. The discount rates used in our discounted cash flow method were based upon on a weighted average cost of capital of industry peers as determined by third party valuation consultants in connection with recent business combinations, adjusted for specific reporting unit risks, which included the level of customer contractual commitments, the level of tangible investment and technological expertise, and the related uncertainty of achieving our budgeted cash flows. A terminal value was applied to the final year of projected cash flows projecting our expectations for stable long-term growth. We then calculated the present value of the discounted discrete and terminal value cash flows to arrive at an estimate of fair value under the income approach. The discounted cash flow results indicated that the estimated fair value of our water solutions reporting unit was greater than its book value at January 1, 2015.

We supplemented this analysis with a market value analysis, in which we compared the book value of the long-lived assets at January 1, 2015 to the fiscal year 2016 forecasted earnings before interest, taxes, depreciation, and amortization expense, which we believe is consistent with calculations often considered by market participants when negotiating the price to be paid for the acquisition of similar businesses. We believe the resulting multiple is reasonably less than the amount that a market participant would be expected to pay, including the following considerations:

- The size of the asset portfolio and its geographic diversity;

- The technological capabilities of the Wyoming processing facility, which we believe could be replicated at other locations if future state or federal laws and regulations require more water to be recycled or discharged;

- Forward crude prices in fiscal years 2017 to 2020 are higher than forward prices in fiscal year 2016; and

- Our solids disposal business, which began in fiscal year 2015 and which earns higher margins and which we expect will enhance the long-term cash flows of our water solutions business.

Finally, we compared our combined estimates of fair value for all of our segments to our total market capitalization as of January 1, 2015, without considering a control premium. Based upon the analyses performed, we concluded that our water segment did not fail step one of the goodwill impairment test, and the estimated fair value for each our reporting units exceeded its respective carrying value and that the goodwill assigned to each reporting unit was not impaired.

We evaluate 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 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.

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

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estimates and assumptions are very subjective and can vary over time. We have recorded a liability of $3.9 million at March 31, 2015. This liability is related to facilities for which we have contractual and regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are retired.

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 represents 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 us 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. At the time 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 represents 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 us 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. At the time 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

Storage tanks require a certain minimum amount of product to remain in the tank as long as the tank is in service. This product is known as tank bottoms. We report tank bottoms we own in storage facilities we own at historical cost within property, plant and equipment on our consolidated balance sheets. The following table summarizes the tank bottoms reported in our consolidated balance sheet at March 31, 2015 (in thousands):

Product	Volume		Book Value
Gasoline (barrels)	219	$	25,710
Crude oil (barrels)	184		16,835
Diesel (barrels)	124		15,153
Renewables (barrels)	41		4,220
Other	504		738
Total		$	62,656

Linefill

We have entered into long-term commitments to ship 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. At March 31, 2015, linefill consisted of 487,104 barrels of crude oil with a book value of $35.1 million.

Business Combinations

We have made in the past, and expect to make in the future, acquisitions of other businesses. We record business combinations using the acquisition method, in which the assets acquired and liabilities assumed are recorded at their acquisition date

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fair values. Fair values of assets acquired and liabilities assumed are based upon available information and may involve us 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 and transportation contracts, and employee compensation commitments. 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 fair value of the assets acquired and liabilities assumed in a business combination. The impact of subsequent changes to the identification of assets and liabilities may require retrospective adjustments to our previously reported consolidated financial position and results of operations.

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 sale 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 of March 31. 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.

Equity-Based Compensation

Our general partner has granted certain restricted units to employees and directors under a long-term incentive plan. These units vest in tranches, subject to the continued service of the recipients.

We record the expense for the first tranche of each 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 distribution growth.

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, 2015, we had $1.4 billion of outstanding borrowings under our Revolving Credit Facility at a rate of 2.18%. A change in interest rates of 0.125% would result in an increase or decrease of our annual interest expense of $1.7 million, based on borrowings outstanding at March 31, 2015.

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The TLP Credit Facility is variable-rate debt with interest rates that are generally indexed to bank prime or LIBOR interest rates. At March 31, 2015, TLP had $250.0 million of outstanding borrowings under the TLP Credit Facility at a rate of 2.67%. A change in interest rates of 0.125% would result in an increase or decrease in TLP s annual interest expense of $0.3 million, based on borrowings outstanding at March 31, 2015.

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 netting agreements that allow for offsetting counterparty receivable and payable balances for certain transactions, as deemed appropriate. The principal counterparties associated with our operations at March 31, 2015 were retailers, resellers, energy marketers, producers, refiners, and dealers.

The natural gas liquids and crude oil industries are margin-based and cost-plus businesses in which gross profits depend on the differential of sales prices over supply costs. As a result, our profitability may be impacted by changes in wholesale prices of natural gas liquids and crude oil. When there are sudden and sharp increases in the wholesale cost of natural gas liquids and crude oil, we may not be able to pass on these increases to our customers through retail or wholesale prices. Natural gas liquids and crude oil are commodities and the price we pay for them can fluctuate significantly in response to supply or other market conditions. We have no control over supply or market conditions. In addition, the timing of cost increases can significantly affect our realized margins. Sudden and extended wholesale price increases could reduce our gross margins and could, if continued over an extended period of time, reduce demand by encouraging end users to conserve or convert to alternative energy sources.

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, 2015 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)	$ (4,992)
Crude oil (water solutions segment)	(1,813)
Propane (liquids segment)	484
Other products (liquids segment)	65
Refined products (refined products and renewables segment)	(22,831)
Renewables (refined products and renewables segment)	(936)

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.

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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 at March 31, 2015. Based on this evaluation, the principal executive officer and principal financial officer of our general partner have concluded that as of March 31, 2015, such disclosure controls and procedures were effective to provide the reasonable assurance described above.

Changes in Internal Control Over Financial Reporting

Other than changes that have resulted or may result from our acquisitions during the year ended March 31, 2015, as discussed below, 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, 2015 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

We acquired TransMontaigne LLC (TransMontaigne) (formerly TransMontaigne Inc.) and certain related operations in July 2014, as described in Note 4 to our consolidated financial statements included in this Annual Report on Form 10 K (Annual Report). At this time, we continue to evaluate the business and internal controls and processes associated with TransMontaigne and are making various changes to its operating and organizational structure based on our business plan. We are in the process of implementing our internal control structure over this acquired business. We expect that our evaluation and integration efforts related to those operations will continue into future fiscal quarters.

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.

As permitted by SEC rules, we have excluded the refined products marketing operations of TransMontaigne and certain related operations from our evaluation of the effectiveness of internal control over financial reporting for the year ended March 31, 2015 due to their size and complexity and the limited time available to complete the evaluation. The operations excluded from our evaluation represent 9% of our total assets at March 31, 2015, and 23% of our total revenues for the year ended March 31, 2015. We have not excluded TransMontaigne Partners L.P. (TLP) from our evaluation of the effectiveness of internal control over financial reporting for the year ended March 31, 2015, as TLP is a publicly traded limited partnership that is responsible for establishing and maintaining adequate internal control over financial reporting.

Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective at March 31, 2015.

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Our internal control over financial reporting at March 31, 2015 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 and Financial Statement Schedules in this Annual Report.

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 shows information regarding the current directors of our general partner and our executive officers.

Name	Age	Position with NGL Energy Holdings LLC
H. Michael Krimbill	61	Chief Executive Officer and Director
Atanas H. Atanasov	42	Chief Financial Officer and Treasurer
James J. Burke	59	President and Director
Shawn W. Coady	53	President and Chief Operating Officer, Retail Division and Director
Vincent J. Osterman	58	President, Eastern Retail Propane Operations and Director
James M. Collingsworth	60	Director
Stephen L. Cropper	65	Director
Bryan K. Guderian	55	Director
James C. Kneale	63	Director
John T. Raymond	44	Director
Patrick Wade	45	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 through 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.

Atanas H. Atanasov. Mr. Atanasov was appointed as our Chief Financial Officer in May 2013. Mr. Atanasov joined our management team in November 2011, and previously served as our Senior Vice President of Finance and Treasurer. Prior to joining NGL, Mr. Atanasov spent nine years at GE Capital, working in lending and leveraged equity. Prior to GE Capital, Mr. Atanasov was with The Williams Companies, Inc. Mr. Atanasov currently serves on the board of directors of TransMontaigne Partners L.P. Mr. Atanasov is a CPA and holds an M.B.A. from the University of Tulsa and a B.S. in Accounting from Oral Roberts University.

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. 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. Mr. Burke received his B.S. from University of Colorado in 1978.

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 Hicks LLC, and the membership interests in Hicks LLC were contributed to us as part of our formation transactions. Dr. Coady was an executive officer of Bachtold Brothers, Incorporated, a family owned company, when it filed for Chapter 7 bankruptcy protection in October 2005. Dr. Coady was also the President of Gifford from March 1989 until the membership interests in Gifford were contributed to us as part of our formation transactions. Dr. Coady has served as a director and as a member of the executive committee of the Illinois Propane Gas Association from 2004 to March 2015. Dr. Coady has also served as the Illinois state director of the National Propane Gas Association from 2004 to March 2015. Dr. Coady has a B.A. in Chemistry from Emory University and an O.D. from the University of Houston. Dr. Coady is the brother of Mr. Coady.

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 national and state propane gas 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 serves as a director 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.

James M. Collingsworth. Mr. Collingsworth has served on our board of directors 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 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 is a former CPA and has a B.B.A. in Accounting in 1973 from West Texas A&M in Canyon, Texas.

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.

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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 is also currently 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. Mr. Raymond received a B.S.M. from the A.B. Freeman School of Business at Tulane University with dual concentrations in finance and accounting and currently sits on the Board of the Business School Council.

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 United States Rockies. 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 serves on the board of directors of Medallion Midstream, L.L.C., Ferus Inc., and Lodestar Energy Group, LLC. Mr. Wade received his Bachelor s degree from the University of Oklahoma in 1991 and his M.B.A. from the Jesse H. Jones School of Management at Rice University in 1995.

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.

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 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 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.

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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, 2015, except as described in the table below.

Reportable Event	Name of Filer	Number of Transactions Reported Late	Average Delay (1)
Sale of units	David C. Kehoe	1	3 days
	Vincent J. Osterman	4	1 day
Restricted units net settled for income tax withholding	Atanas H. Atanasov	2	10 days
	James J. Burke	1	18 days
	Shawn W. Coady	2	10 days
	Todd M. Coady	2	10 days
	Jeffrey A. Herbers	2	10 days
	David C. Kehoe	1	18 days
	Vincent J. Osterman	2	10 days
Conversion of subordinated units to common units	Shawn W. Coady	1	2 days
	Todd M. Coady	1	2 days
	H. Michael Krimbill	1	3 days
Grant of unvested restricted units under compensation programs	Atanas H. Atanasov	1	14 days
	Shawn W. Coady	1	14 days
	Todd M. Coady	1	14 days
	Jeffrey A. Herbers	1	14 days
	Vincent J. Osterman	1	14 days

(1) Represents the average number of business days by which the filing deadlines were missed.

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.

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,

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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 2015 in the Compensation Discussion and Analysis and the summary compensation table refers to our fiscal year ended March 31, 2015.

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 2015 were:

- H. Michael Krimbill Chief Executive Officer
- Atanas H. Atanasov Chief Financial Officer and Treasurer
- James J. Burke President
- Shawn W. Coady President and Chief Operating Officer, Retail Division

- Vincent J. Osterman President, Eastern Retail Propane Operations

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.

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, 2015 included the following:

- Significantly expanded our refined products and renewables segment through the acquisition of TransMontaigne and related operations;

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- Completed a successful open season and began construction of Grand Mesa to transport crude oil from Weld County, Colorado to Cushing, Oklahoma;

- Acquired a strategically-located natural gas liquids salt dome storage facility in Utah; and

- Increased our distribution from $0.5513 per common unit in May 2014 to $0.6250 per common unit in May 2015 (an increase of over 13%).

Compensation Highlights

- We paid no cash bonuses to our named executive officers during fiscal year 2015.

- 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 exceeded the median returns for a specified peer group over specified periods of time.

Factors Enhancing Alignment with Unitholder Interests

- Majority of officer pay is incentive compensation at risk 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 2015, 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 2015:

- 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;

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- Fees paid to PM&P by the Partnership during fiscal year 2015 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;

- 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 2015 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. We use three 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	• Based on the named executive officer s expected contribution	X	X	X

	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	to long-term performance goals

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 Directors increased Mr. Krimbill s salary to $350,000, in

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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. 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.

- 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 this 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.

Cash Bonus Awards

No cash bonuses were paid to the named executive officers during fiscal year 2015. 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). Grants of Service Award units to the named executive officers are summarized below:

	Unvested Units at March 31, 2014	Units Granted in July 2014	Units Granted in March 2015	Units Vested in Fiscal Year 2015	Total Unvested Units at March 31, 2015

Atanas H. Atanasov	32,000	7,000	24,000	(27,000)	36,000
James J. Burke	40,000		25,000	(20,000)	45,000
Shawn W. Coady	10,000	7,000	45,000	(17,000)	45,000
Vincent J. Osterman	10,000	7,000	45,000	(17,000)	45,000

The vesting dates of the unvested Service Award units at March 31, 2015 are summarized below:

	Service Award Units by Vesting Date			Total
	July 1, 2015	**July 1, 2016**	**July 1, 2017**	**Unvested Units at March 31, 2015**
Atanas H. Atanasov	12,000	12,000	12,000	36,000
James J. Burke	15,000	15,000	15,000	45,000
Shawn W. Coady	15,000	15,000	15,000	45,000
Vincent J. Osterman	15,000	15,000	15,000	45,000

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The Service Award units granted in July 2014 were intended as discretionary bonuses for performance during fiscal year 2014. Of the Service Award units granted in March 2015 to Mr. Atanasov and Mr. Burke, 10,000 of the units were intended as a bonus for performance during fiscal year 2015. No Service Award units were granted to Mr. Krimbill until April 2015, at the request of Mr. Krimbill.

The number of Service Award units to be granted was determined by reference to peer groups. Assuming a value of $30 value per unit for this purpose, the annual Service Award value falls between the 25th and 50th percentile of the peer group for Mr. Burke, Dr. Coady, and Mr. Osterman, and below the 25th percentile of the peer group for Mr. Atanasov.

Fiscal Year 2016 Awards

During April 2015, the board of directors granted certain Service Award units to Mr. Krimbill, which will vest in tranches of 71,191 each on July 1, 2015, July 1, 2016, and July 1, 2017. The number of award units was calculated based on the median value of equity award units granted to chief executive officers in the benchmark peer group.

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 maximum number of units that could vest on the Performance Awards granted to each named executive officer is summarized below:

	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

The percentage of the maximum Performance Award units that will vest will depend on the percentage of entities in the Index that NGL outperforms, as summarized in the table below:

Performance Relative to Index	Percentage of Maximum Performance Award Units to Vest
Less than 50th percentile	0%
50th 75th percentile	25% 50%
75th 90th percentile	50% 100%
Greater than 90 percentile	100%

The Performance Award units were determined 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.

Under the provisions of Accounting Standards Codification (ASC) 718, the grant date for the Performance Award units was in April 2015, as the performance metrics were not finalized and communicated to the recipients until April 2015. As a result, these awards are not listed in the Summary Compensation Table for fiscal year 2015 below.

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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.

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 an employer matching contribution equal to 3.5% of the employee s contribution 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 2015 Compensation Program

During fiscal year 2015, 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

- 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

[redacted]

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 2015 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.

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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 2015, 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 2015. Shawn Coady is an executive officer and a member of the board of directors. 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 2015

The following table includes the compensation earned by our named executive officers for fiscal years 2013 through 2015.

Name and Position	Fiscal Year	Salary ($)	Bonus (1) ($)	Restricted Unit Awards (2) ($)	All Other Compensation (3) ($)	Total ($)
H. Michael Krimbill	2015	292,500			9,319	301,819
Chief Executive Officer	2014	117,693	475,000		6,493	599,186
	2013	82,849			2,492	85,341
Atanas H. Atanasov	2015	287,500		864,664	9,346	1,161,510
Chief Financial Officer	2014	232,500	195,000	259,696	7,038	694,234
	2013	195,000		743,440	2,738	941,178
James J. Burke (4)	2015	381,750		602,270	26,467	1,010,487
President	2014	367,385	450,000		24,651	842,036
	2013	275,630		836,400	13,015	1,125,045
Shawn W. Coady	2015	311,250		1,331,501	19,153	1,661,904
President and Chief Operating	2014	300,000	200,000		19,630	519,630
Officer, Retail Division	2013	238,462		613,700	17,730	869,892
Vincent J. Osterman (5)	2015	250,000		1,331,501	31,763	1,613,264
President, Eastern Retail						
Propane Operations						

(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 limited partner 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.

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(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). These amounts are summarized in the table below:

Name	Fiscal Year	401 (k) Match	Car Allowance	Club Membership	Propane	Total Other Compensation
James J. Burke	2015	$ 9,343	$ 9,000	$ 8,124	$	$ 26,467
	2014	7,527	9,000	8,124		24,651
	2013	4,891		8,124		13,015
Shawn W. Coady	2015	9,796	9,357			19,153
	2014	8,750	10,880			19,630
	2013	7,154	10,576			17,730
Vincent J. Osterman	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.

Restricted Unit Awards

During fiscal year 2015, 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).

2015 Grants of Plan Based Awards Table

The number of restricted Service Award units granted to our named executive officers, and their grant date fair values, are summarized below:

Name	Grant Date	Total Number of Service Award Units	Grant Date Fair Value of Service Award Units ($)
H. Michael Krimbill	n/a		
Atanas H. Atanasov	July 24, 2014	7,000	307,090

	March 30, 2015	24,000	557,574
James J. Burke	March 30, 2015	25,000	602,270
Shawn W. Coady	July 24, 2014	7,000	307,090
	March 30, 2015	45,000	1,024,411
Vincent J. Osterman	July 24, 2014	7,000	307,090
	March 30, 2015	45,000	1,024,411

The fair value of the restricted Service Award units shown in the table above were calculated based on the closing market price of our limited partner 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 as of March 31, 2015

The number of unvested Service Award units outstanding at March 31, 2015, and their fair values at March 31, 2015, are summarized below:

Name	Number of Service Award Units That Have Not Yet Vested at March 31, 2015	Fair Value of Unvested Service Award Units as of March 31, 2015 ($)
H. Michael Krimbill		
Atanas H. Atanasov	36,000	944,280
James J. Burke	45,000	1,180,350
Shawn W. Coady	45,000	1,180,350
Vincent J. Osterman	45,000	1,180,350

The fair values of the restricted units shown in the table above were calculated based on the closing market price of our common units at March 31, 2015 of $26.23. No adjustments were made to reflect the fact that the restricted units are not entitled to distributions during the vesting period.

2015 Option Exercises and Stock Vested

During fiscal year 2015, certain of the restricted Service Award units vested. The value of the awards on the vesting date summarized in the table below was calculated based of the closing market price per unit on the vesting dates.

Name	Number of Units Acquired on Vesting	Value Realized on Vesting ($)
H. Michael Krimbill		
Atanas H. Atanasov	27,000	989,770
James J. Burke	20,000	694,300
Shawn W. Coady	17,000	727,470
Vincent J. Osterman	17,000	727,470

Upon vesting, certain of the named executive officers elected for us to remit payments to taxing authorities in lieu of issuing units. The following table summarizes the number of units issued and the number of units withheld for taxes:

Name	Number of Units Issued	Number of Units Withheld	Total
Atanas H. Atanasov	18,149	8,851	27,000

James J. Burke	13,333	6,667	20,000
Shawn W. Coady	10,501	6,499	17,000
Vincent J. Osterman	14,718	2,282	17,000

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 units that vested and were issued during fiscal year 2015:

Name	Distributions
Atanas H. Atanasov	$ 18,020
James J. Burke	12,376
Shawn W. Coady	16,271
Vincent J. Osterman	23,935

Performance Awards

As described under Long-Term Equity Incentive Awards in the Compensation Discussion and Analysis earlier in this Item 11, the Compensation Committee has also granted restricted unit awards that are contingent both on the continued service of the recipients through the vesting date and also on the performance of NGL s common units relative to the performance of other entities in the Alerian MLP Index (the Performance Awards). These Performance Award units are not included in the Summary Compensation Table for 2015 and related disclosures above, as the grant date of the Performance Award units was in fiscal year 2016.

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Potential Payments upon Termination or Change in Control

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 as of March 31, 2015 table above.

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 June 2012, such directors were granted restricted units that vested in tranches of 5,000 units each on January 1, 2013, July 1, 2013, and July 1, 2014. In April 2015, such directors were granted 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 2015

The following table summarizes the compensation earned during fiscal year 2015 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			
Stephen L. Cropper	65,000		65,000
Bryan K. Guderian	65,000		65,000
James C. Kneale	70,000		70,000

Mr. Collingsworth joined the board of directors in January 2015. He will earn annual fees to be paid in cash of $65,000.

These directors did not receive any equity grants under the LTIP during fiscal year 2015. During fiscal year 2013, Mr. Cropper, Mr. Guderian, and Mr. Kneale received a grant of unvested units under the LTIP. These units vested in tranches, contingent on the continued service of the directors. During fiscal year 2015, a tranche of 5,000 units vested for each of these directors. Subsequent to the vesting, these individuals received distributions of $1.82 on each of the vested units.

During April 2015, the board of directors granted restricted units to the four directors listed above. For each of these directors, the awards will vest in tranches of 5,000 each on July 1, 2015, July 1, 2016, and July 1, 2017.

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 25, 2015 of our units by:

- each person or group of persons known by us to be a beneficial owner of more than 5% of our outstanding units;

- each director of our general partner;

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- 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)	10,304,835	9.69%
Magnum NGL HoldCo LLC (3)	7,396,973	6.96%
Neuberger Berman Group LLC (4)	5,374,770	5.05%
Directors and officers:		
Atanas H. Atanasov (5)	66,073	*
James J. Burke (6)	326,285	*
Shawn W. Coady (7)	2,502,231	2.35%
James M. Collingsworth (8)	17,000	*
Stephen L. Cropper (9)	40,000	*
Bryan K. Guderian	35,000	*
James C. Kneale (10)	34,500	*
H. Michael Krimbill (11)	1,741,976	1.64%
Vincent J. Osterman (12)	3,931,095	3.70%
John T. Raymond (13)	176,634	*
Patrick Wade		
All directors and executive officers as a group (11 persons) (14)	8,870,794	8.34%

* Less than 1.0%

(1) Based on 106,328,594 common units outstanding at May 25, 2015.

(2) The mailing address for OppenheimerFunds, Inc. is Two World Financial Center, 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 Form 13G filed with the SEC on February 6, 2015.

(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 Form 13G filed with the SEC on February 27, 2015.

(4) The mailing address for Neuberger Berman Group LLC is 605 Third Avenue, 41st Floor, New York, NY 10158. Neuberger Berman Group LLC reported shared voting and dispositive power with respect to all common units beneficially owned. This information related to Neuberger Berman Group LLC is based upon its Form 13G filed with the SEC on February 6, 2015.

(5) Atanas H. Atanasov also owns a 0.40% interest in our general partner.

(6) 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) Shawn W. Coady owns 71,840 of these common units. 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 Shawn W. Coady is the sole partner. Shawn W. 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 110,000 of these common units. Shawn W. 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. Shawn W. 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) James M. Collingsworth owns 15,000 of these common units. James M. Collingsworth holds 2,000 common units jointly with his spouse, Cindy Collingsworth.

(9) Stephen L. Cropper owns 15,000 of these common units. The Donna L. Cropper Living Trust owns 25,000 of these common units. Stephen L. Cropper and his spouse, Donna L. Cropper, are the Trustees of the Trust.

(10) James C. Kneale owns 15,000 of these common units. The Suzanne and Jim Kneale Living Trust owns 19,500 of these common units.

(11) H. Michael Krimbill owns 453,573 of these common units. Krim2010, LLC owns 904,848 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 20,000 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 exercises the sole voting and disposition power for Krimbill Enterprises LP, and disclaims beneficial ownership of these securities except to the extent of his pecuniary interest therein. 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. 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. 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.

(12) Vincent J. Osterman owns 76,458 of these common units. 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 745,758 common units and shared voting and investment power (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 0.75% interest in our general partner through VE Properties XI LLC.

(13) EMG NGL HC, LLC owns all of these 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 42.20% 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.

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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, 2015.

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)	2,260,400		7,080,006
Total	2,260,400		7,080,006

(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 31,947,372 common units, representing an aggregate 30.05% 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 payments were determined by and among affiliated entities before our IPO and, consequently, are not the result of arm s length negotiations.

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[redacted]

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 in our consolidated statements of operations (although 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 transactions with SemGroup are summarized below for the year ended March 31, 2015 (in thousands):

Sales to SemGroup	$	290,172
Purchases from SemGroup		332,030

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WPX

Bryan 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). 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, which included WPX, requested to be released from the commitments. We agreed to release WPX from its commitments in return for a cash payment in March 2015 and additional cash payments over the next five years. These payments are included in the sales to WPX in the table below. The transactions with WPX are summarized below for the year ended March 31, 2015 (in thousands):

Income from WPX	$	325,141
Purchases from WPX		371,540

Other Transactions

We purchase goods and services from certain entities that are partially owned by our executive officers. These transactions are summarized below for the year ended March 31, 2015:

Entity	**Nature of Purchases**		**Amount Purchased (in thousands)**	**Ownership Interest in Entity**
Dr. Coady:				
Hicks Motor Sales	Vehicle purchases	$	551	50.0%
Mr. Kehoe:				
Cowhouse Partners, L.L.C	Terminaling services and transportation services		143	27.5%
Fluid Services, LLC	Condensate purchases and transportation services		337	20.0%
Mr. Osterman:				
VE Properties III, LLC	Office space rental		149	100.0%

As of March 31, 2015, we no longer purchase goods or services from Cowhouse Partners, L.L.C. or Fluid Services, LLC.

We provide goods and services to several entities that are partially owned by our executive officers. These transactions are summarized below for the year ended March 31, 2015:

	Revenues	**Ownership Interest**

Entity	Nature of Services	Generated (in thousands)		in Entity
Mr. Burke:				
Impact Energy Services, LLC	Truck transportation services	$	552	50.0%

Todd Coady, an employee of the Partnership, is the brother of Shawn Coady, who is an officer of the Partnership and a member of the board of directors. Todd Coady s annual base compensation was $225,000 until July 1, 2014, when it was increased to $250,000. Todd Coady was also eligible to participate in the Partnership s 401(k) plan, and he received $7,077 of employer matching contributions during the year ended March 31, 2015. In July 2014, Todd Coady was granted a bonus of 5,000 restricted units that vested during August 2014. The grant date fair value of this bonus was $219,350. Todd Coady was also granted 24,000 restricted units

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that are scheduled to vest in three tranches of 8,000 units each on July 1, 2015, July 1, 2016, and July 1, 2017. The aggregate grant date fair value of these awards was $546,353.

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, 2015 was $110,000. Timothy Osterman was also eligible to participate in the Partnership s 401(k) plan, and he received $3,515 of employer matching contributions during the year ended March 31, 2015. In July 2014, Tim Osterman was granted a bonus of 3,000 restricted units that vested during August 2014. The grant date fair value of this bonus was $131,610. Tim Osterman was also granted 2,000 restricted units that are scheduled to vest in two tranches of 1,000 units each on July 1, 2015 and July 1, 2016. The aggregate grant date fair value of these awards was $48,271.

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 eight 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;

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- 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.

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 Accountant 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 years ended March 31, 2015 and 2014:

	2015	2014
Audit fees (1)	$ 2,762,764	$ 2,531,229
Audit-related fees		
Tax fees (2)	30,000	70,091
All other fees		
Total	$ 2,792,764	$ 2,601,320

(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 and 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*.

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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)
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)

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Exhibit Number	Description
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)

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Exhibit Number	Description
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
4.10	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)
4.11	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)
4.12	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)
4.13	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)
4.14	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)
4.15	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)
4.16	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)
4.17	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)
4.18*	Amendment No. 8 to Note Purchase Agreement, dated as of May 1, 2015, among the Partnership and the purchasers named therein
4.19	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)
4.20	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)
4.21	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)
4.22	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)

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Exhibit Number	Description
4.23	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)
4.24*	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
4.25*	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
4.26	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)
4.27	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)
4.28	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)
4.29	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)
4.30	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)
4.31	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)
4.32*	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
4.33*	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
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
10.14	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)

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Exhibit Number	Description
10.15+	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)
10.16+	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)
10.17+	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)
10.18*+	NGL Performance Unit Program
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, 2015 and 2014, (ii) Consolidated Statements of Operations for the years ended March 31, 2015, 2014, and 2013, (iii) Consolidated Statements of Comprehensive Income for the years ended March 31, 2015, 2014, and 2013, (iv) Consolidated Statements of Changes in Equity for the years ended March 31, 2015, 2014, and 2013, (v) Consolidated Statements of Cash Flows for the years ended March 31, 2015, 2014, and 2013, 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 June 1, 2015.

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)	June 1, 2015
/s/ Atanas H. Atanasov Atanas H. Atanasov	Chief Financial Officer (Principal Financial Officer)	June 1, 2015
/s/ Jeffrey A. Herbers Jeffrey A. Herbers	Chief Accounting Officer (Principal Accounting Officer)	June 1, 2015
/s/ James J. Burke James J. Burke	Director	June 1, 2015
/s/ Shawn W. Coady Shawn W. Coady	Director	June 1, 2015
/s/ James M. Collingsworth James M. Collingsworth	Director	June 1, 2015
/s/ Stephen L. Cropper Stephen L. Cropper	Director	June 1, 2015
/s/ Bryan K. Guderian Bryan K. Guderian	Director	June 1, 2015
/s/ James C. Kneale James C. Kneale	Director	June 1, 2015
/s/ Vincent J. Osterman Vincent J. Osterman	Director	June 1, 2015

John T. Raymond	Director	June 1, 2015
Patrick Wade	Director	June 1, 2015

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INDEX TO FINANCIAL STATEMENTS

NGL ENERGY PARTNERS LP

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

NGL Energy Partners LP

We have audited the accompanying consolidated balance sheets of NGL Energy Partners LP (a Delaware limited partnership) and subsidiaries (the Partnership) as of March 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended March 31, 2015. These financial statements are the responsibility of the Partnership s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of NGL Energy Partners LP and subsidiaries as of March 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2015 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership s internal control over financial reporting as of March 31, 2015, based on criteria established in the 2013 *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated June 1, 2015 expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
June 1, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners

NGL Energy Partners LP

We have audited the internal control over financial reporting of NGL Energy Partners LP (a Delaware limited partnership) and subsidiaries (the Partnership) as of March 31, 2015, based on criteria established in the 2013 *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting (Management s Report). Our responsibility is to express an opinion on the Partnership s internal control over financial reporting based on our audit. Our audit of, and opinion on, the Partnership s internal control over financial reporting does not include the internal control over financial reporting of the refined products marketing operations of TransMontaigne LLC (TransMontaigne) and certain related operations whose financial statements reflect total assets and revenues constituting 9 and 23 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended March 31, 2015. As indicated in Management s Report, the refined products marketing operations of TransMontaigne and certain related operations were acquired during the year ended March 31, 2015. Management s assertion on the effectiveness of the Partnership s internal control over financial reporting excluded internal control over financial reporting of the refined products marketing operations of TransMontaigne and certain related operations.

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

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

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

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of March 31, 2015, based on criteria established in the 2013 *Internal Control Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Partnership as of and for the year ended March 31, 2015, and our report dated June 1, 2015 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
June 1, 2015

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NGL ENERGY PARTNERS LP AND SUBSIDIARIES

Consolidated Balance Sheets

(U.S. Dollars in Thousands, except unit amounts)

	March 31, 2015	March 31, 2014
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 41,303	$ 10,440
Accounts receivable trade, net of allowance for doubtful accounts of $4,367 and $2,822, respectively	1,024,226	877,904
Accounts receivable affiliates	17,198	7,445
Inventories	441,762	310,160
Prepaid expenses and other current assets	120,855	80,350
Total current assets	1,645,344	1,286,299
PROPERTY, PLANT AND EQUIPMENT, net of accumulated depreciation of $202,959 and $109,564, respectively	1,617,389	835,848
GOODWILL	1,402,761	1,085,393
INTANGIBLE ASSETS, net of accumulated amortization of $220,517 and $116,728, respectively	1,288,343	736,106
INVESTMENTS IN UNCONSOLIDATED ENTITIES	472,673	194,821
LOAN RECEIVABLE AFFILIATES	8,154	
OTHER NONCURRENT ASSETS	112,837	9,164
Total assets	$ 6,547,501	$ 4,147,631
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable trade	$ 833,380	$ 719,303
Accounts payable affiliates	25,794	76,846
Accrued expenses and other payables	195,116	141,690
Advance payments received from customers	54,234	29,965
Current maturities of long-term debt	4,472	7,080
Total current liabilities	1,112,996	974,884
LONG-TERM DEBT, net of current maturities	2,745,299	1,629,834
OTHER NONCURRENT LIABILITIES	16,086	11,060
COMMITMENTS AND CONTINGENCIES		
EQUITY:		
General partner, representing a 0.1% interest, 103,899 and 79,420 notional units at March 31, 2015 and 2014, respectively	(37,021)	(45,287)
Limited partners, representing a 99.9% interest -		
Common units, 103,794,870 and 73,421,309 units issued and outstanding at March 31, 2015 and 2014, respectively	2,162,924	1,570,074
Subordinated units, 5,919,346 units issued and outstanding at March 31, 2014		2,028
Accumulated other comprehensive loss	(109)	(236)
Noncontrolling interests	547,326	5,274
Total equity	2,673,120	1,531,853
Total liabilities and equity	$ 6,547,501	$ 4,147,631

The accompanying notes are an integral part of these consolidated financial statements.

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NGL ENERGY PARTNERS LP AND SUBSIDIARIES

Consolidated Statements of Operations

(U.S. Dollars in Thousands, except unit and per unit amounts)

	Year Ended March 31, 2015	2014	2013
REVENUES:			
Crude oil logistics	$ 6,635,384	$ 4,558,545	$ 2,316,288
Water solutions	200,042	143,100	62,227
Liquids	2,243,825	2,650,425	1,604,746
Retail propane	489,197	551,815	430,273
Refined products and renewables	7,231,693	1,357,676	
Other	1,916	437,713	4,233
Total Revenues	16,802,057	9,699,274	4,417,767
COST OF SALES:			
Crude oil logistics	6,560,506	4,477,397	2,244,647
Water solutions	(30,506)	11,738	5,611
Liquids	2,111,614	2,518,099	1,530,459
Retail propane	278,538	354,676	258,393
Refined products and renewables	7,035,472	1,344,176	
Other	2,583	426,613	
Total Cost of Sales	15,958,207	9,132,699	4,039,110
OPERATING COSTS AND EXPENSES:			
Operating	372,176	259,799	169,612
Loss on disposal or impairment of assets, net	41,184	3,597	187
General and administrative	149,430	75,860	52,698
Depreciation and amortization	193,949	120,754	68,853
Operating Income	87,111	106,565	87,307
OTHER INCOME (EXPENSE):			
Earnings of unconsolidated entities	12,103	1,898	
Interest expense	(110,123)	(58,854)	(32,994)
Loss on early extinguishment of debt			(5,769)
Other income, net	37,171	86	1,521
Income Before Income Taxes	26,262	49,695	50,065
INCOME TAX (PROVISION) BENEFIT	3,622	(937)	(1,875)
Net Income	29,884	48,758	48,190
LESS: NET INCOME ALLOCATED TO GENERAL PARTNER	(45,679)	(14,148)	(2,917)
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(13,223)	(1,103)	(250)
NET INCOME (LOSS) ALLOCATED TO LIMITED PARTNERS	$ (29,018)	$ 33,507	$ 45,023
BASIC AND DILUTED INCOME (LOSS) PER COMMON UNIT	$ (0.29)	$ 0.51	$ 0.96

BASIC AND DILUTED WEIGHTED AVERAGE COMMON UNITS OUTSTANDING	86,359,300	61,970,471	41,353,574

The accompanying notes are an integral part of these consolidated financial statements.

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NGL ENERGY PARTNERS LP AND SUBSIDIARIES

Consolidated Statements of Comprehensive Income

(U.S. Dollars in Thousands)

	Year Ended March 31, 2015	2014	2013
Net income	$ 29,884	$ 48,758	$ 48,190
Other comprehensive income (loss)	127	(260)	(7)
Comprehensive income	$ 30,011	$ 48,498	$ 48,183

The accompanying notes are an integral part of these consolidated financial statements.

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NGL ENERGY PARTNERS LP AND SUBSIDIARIES

Consolidated Statements of Changes in Equity

For the Years Ended March 31, 2015, 2014, and 2013

(U.S. Dollars in Thousands, except unit amounts)

		Limited Partners						
	General Partner	Common Units	Amount	Subordinated Units	Amount	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
BALANCES AT MARCH 31, 2012	$ 442	23,296,253	$ 384,604	5,919,346	$ 19,824	$ 31	$ 428	$ 405,329
Distributions	(1,778)		(59,841)		(9,989)		(74)	(71,682)
Contributions	510						403	913
Business combinations	(52,588)	24,250,258	550,873				4,733	503,018
Equity issued pursuant to incentive compensation plan		156,802	3,657					3,657
Net income	2,917		41,705		3,318		250	48,190
Other comprehensive loss						(7)		(7)
BALANCES AT MARCH 31, 2013	(50,497)	47,703,313	920,998	5,919,346	13,153	24	5,740	889,418
Distributions	(9,703)		(123,467)		(11,920)		(840)	(145,930)
Contributions	765						2,060	2,825
Business combinations		2,860,879	80,591					80,591
Sales of units, net of offering costs		22,560,848	650,155					650,155
Equity issued pursuant to incentive compensation plan		296,269	9,085					9,085
Disposal of noncontrolling interest							(2,789)	(2,789)
Net income	14,148		32,712		795		1,103	48,758
Other comprehensive loss						(260)		(260)
BALANCES AT MARCH 31, 2014	(45,287)	73,421,309	1,570,074	5,919,346	2,028	(236)	5,274	1,531,853
Distributions	(38,236)		(197,611)		(6,748)		(27,147)	(269,742)
Contributions	823						9,433	10,256
Business combinations		8,851,105	259,937				546,740	806,677
Sales of units, net of offering costs		15,017,100	541,128					541,128
Equity issued pursuant to incentive compensation plan		586,010	23,134					23,134
Net income (loss)	45,679		(25,005)		(4,013)		13,223	29,884
Other comprehensive income						127		127
Conversion of subordinated units to common units		5,919,346	(8,733)	(5,919,346)	8,733			
Other							(197)	(197)

BALANCES AT MARCH 31, 2015	$	(37,021)	103,794,870	$	2,162,924			$		$	(109)	$	547,326	$	2,673,120

The accompanying notes are an integral part of these consolidated financial statements.

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NGL ENERGY PARTNERS LP AND SUBSIDIARIES

Consolidated Statements of Cash Flows

(U.S. Dollars in Thousands)

	Year Ended March 31, 2015	2014	2013
OPERATING ACTIVITIES:			
Net income	$ 29,884	$ 48,758	$ 48,190
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization	210,475	132,653	77,513
Loss on early extinguishment of debt			5,769
Non-cash equity-based compensation expense	32,767	14,054	8,670
Loss on disposal or impairment of assets, net	41,184	3,597	187
Provision for doubtful accounts	3,838	2,172	1,315
Commodity derivative (gain) loss	(219,421)	43,655	4,376
Earnings of unconsolidated entities	(12,103)	(1,898)	
Distributions of earnings from unconsolidated entities	12,539		
Other	127	312	375
Changes in operating assets and liabilities, exclusive of acquisitions:			
Accounts receivable trade	50,887	21,388	2,562
Accounts receivable affiliates	(9,225)	18,002	(12,877)
Inventories	243,292	(73,321)	18,433
Prepaid expenses and other assets	(34,505)	20,308	22,585
Accounts payable trade	(1,965)	(167,060)	(16,913)
Accounts payable affiliates	(51,121)	67,361	(6,813)
Accrued expenses and other liabilities	(53,844)	(41,671)	(9,689)
Advance payments received from customers	19,585	(3,074)	(11,049)
Net cash provided by operating activities	262,394	85,236	132,634
INVESTING ACTIVITIES:			
Purchases of long-lived assets	(203,760)	(165,148)	(72,475)
Purchases of pipeline capacity allocations	(24,218)		
Purchase of equity interest in Grand Mesa Pipeline	(310,000)		
Acquisitions of businesses, including acquired working capital, net of cash acquired	(960,922)	(1,268,810)	(490,805)
Cash flows from commodity derivatives	199,165	(35,956)	11,579
Proceeds from sales of assets	26,262	24,660	5,080
Investments in unconsolidated entities	(33,528)	(11,515)	
Distributions of capital from unconsolidated entities	10,823	1,591	
Loan for facility under construction	(63,518)		
Payments on loan for facility under construction	1,625		
Loans to affiliates	(8,154)		
Other	4	(195)	
Net cash used in investing activities	(1,366,221)	(1,455,373)	(546,621)
FINANCING ACTIVITIES:			
Proceeds from borrowings under revolving credit facilities	3,764,500	2,545,500	1,227,975
Payments on revolving credit facilities	(3,280,000)	(2,101,000)	(964,475)
Issuances of notes	400,000	450,000	250,000

Proceeds from borrowings on other long-term debt		880	653
Payments on other long-term debt	(6,688)	(8,819)	(4,837)
Debt issuance costs	(11,076)	(24,595)	(20,189)
Contributions from general partner	823	765	510
Contributions from noncontrolling interest owners	9,433	2,060	403
Distributions to partners	(242,595)	(145,090)	(71,608)
Distributions to noncontrolling interest owners	(27,147)	(840)	(74)
Proceeds from sale of common units, net of offering costs	541,128	650,155	(642)
Taxes paid on behalf of equity incentive plan participants	(13,491)		
Other	(197)		
Net cash provided by financing activities	1,134,690	1,369,016	417,716
Net increase (decrease) in cash and cash equivalents	30,863	(1,121)	3,729
Cash and cash equivalents, beginning of period	10,440	11,561	7,832
Cash and cash equivalents, end of period	$ 41,303	$ 10,440	$ 11,561

The accompanying notes are an integral part of these consolidated financial statements.

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NGL ENERGY PARTNERS LP AND SUBSIDIARIES

Notes to Consolidated Financial Statements

At March 31, 2015 and 2014, and for the Years Ended March 31, 2015, 2014, and 2013

Note 1 Nature of Operations and Organization

NGL Energy Partners LP (we, us, our, or the Partnership) is a Delaware limited 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 below. At March 31, 2015, our operations include:

- Our crude oil logistics segment, the assets of which include owned and leased crude oil storage terminals, owned and leased pipeline injection stations, a fleet of owned trucks and trailers, a fleet of owned and leased railcars, a fleet of owned and leased barges and towboats, and a 50% interest in a crude oil pipeline. Our crude oil logistics segment purchases crude oil from producers and transports it 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 treatment and disposal facilities. Our water solutions segment generates revenues from the treatment and disposal of wastewater generated from crude oil and natural gas production, from the sale of recycled water and recovered hydrocarbons, and from the disposal of solids such as tank bottoms and drilling fluids.

- 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 services through its 21 owned terminals throughout the United States and railcar transportation services through its fleet of leased railcars. Our liquids segment purchases propane, butane, and other products from refiners, processing plants, producers, and other parties, and sells the products to retailers, refiners, petrochemical plants, and other participants in the wholesale markets.

- 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 also own the 2.0% general partner interest and a 19.6% limited partner interest in TransMontaigne Partners L.P. (TLP), which conducts refined products terminaling operations. TLP also owns a 42.5% interest in Battleground Oil Specialty Terminal Company LLC (BOSTCO) and a 50% interest in Frontera Brownsville LLC (Frontera), which are entities that own refined products storage facilities.

Acquisitions

At the time of our IPO, we owned a retail propane business operating primarily in Illinois and Indiana and a natural gas liquids wholesale business with three natural gas liquids terminals. Subsequent to our IPO, 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, whereby we acquired retail propane operations in the northeastern United States.

- 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., 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.

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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, 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 provides us the right to purchase water treatment and disposal facilities developed by the other party to the agreement, and we are also party to a solids facilities development agreement with this other party. During March 2014, we purchased one additional facility under this development agreement. During the year ended March 31, 2015, we purchased 16 water treatment and disposal facilities 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, 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

- 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 2.0% general partner interest, the incentive distribution rights, a 19.7% limited partner interest in TLP, and assumed certain terminaling service agreements with TLP from an affiliate of the previous owner of TransMontaigne.

- In November 2014, we completed the acquisition of two saltwater disposal facilities in the Bakken shale play in North Dakota.

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• 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 U.S. markets and entered into a construction agreement to expand the storage capacity of the facility.

Note 2 Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). The accompanying consolidated financial statements include our accounts and those of our controlled subsidiaries. Investments where we do not have the ability to exercise control, but do have the ability to exercise significant influence, are accounted for using the equity method of accounting. All significant intercompany transactions and account balances have been eliminated in consolidation.

We have made certain reclassifications to prior period financial statements to conform to classification methods used in fiscal year 2015. These reclassifications had no impact on previously reported amounts of equity or net income. In addition, certain balances at March 31, 2014 were adjusted to reflect the final acquisition accounting for certain business combinations.

Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amount of revenues and expenses during the period.

Critical estimates we make in the preparation of our consolidated financial statements include determining the fair value of assets and liabilities acquired in business combinations; the collectability of accounts receivable; the recoverability of inventories; useful lives and recoverability of property, plant and equipment and amortizable intangible assets; the impairment of goodwill; the fair value of asset retirement obligations; the value of equity-based compensation; and accruals for various commitments and contingencies, among others. Although we believe these estimates are reasonable, actual results could differ from those estimates.

Fair Value Measurements

We apply fair value measurements to certain assets and liabilities, principally our commodity derivative instruments and assets and liabilities acquired in business combinations. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Fair value is based upon assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and risks inherent in valuation techniques and inputs to valuations. This includes not only the credit standing of counterparties and credit enhancements but also the impact of our own nonperformance risk on our liabilities. Fair value measurements assume that the transaction occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability (the market for which the reporting entity would be able to maximize the amount received or minimize the amount paid). We evaluate the need for credit adjustments to our derivative instrument fair values in accordance with the requirements noted above. Such adjustments were not material to the fair values of our derivative instruments.

We use the following fair value hierarchy, which prioritizes the inputs to valuation techniques used to measure fair value into three broad levels:

- Level 1 Quoted prices (unadjusted) in active markets for identical assets and liabilities that we have the ability to access at the measurement date.

- Level 2 Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are observable for the asset or liability, and inputs that are derived from observable market data by correlation or other means. Instruments categorized in Level 2 include non-exchange traded derivatives such as over-the-counter commodity price swap and option contracts and interest rate protection agreements. We determine the fair value of all of our derivative financial instruments utilizing pricing models for significantly similar instruments. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties.

- Level 3 Unobservable inputs for the asset or liability including situations where there is little, if any, market activity for the asset or liability.

The fair value hierarchy gives the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall into different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement requires judgment, considering factors specific to the asset or liability.

Derivative Financial Instruments

We record our derivative financial instrument contracts at fair value in our consolidated balance sheets, with changes in the fair value of our commodity derivative instruments included in our consolidated statements of operations in cost of sales. Contracts that qualify for the normal purchase or sale election and are designated as such are not accounted for as derivatives at fair value and, accordingly, are recorded when the delivery occurs.

We have not designated any financial instruments as hedges for accounting purposes. All mark-to-market gains and losses on commodity derivative instruments that do not qualify as normal purchases or 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 help reduce our exposure to variability in future commodity prices. 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. We take an active role in managing and controlling market risk and credit risk and have established control procedures that we review on an ongoing basis. We monitor market risk through a variety of techniques and attempt to minimize credit risk exposure through credit policies and periodic monitoring procedures.

Revenue Recognition

We record revenues from product sales at the time title to the product transfers to the purchaser, which typically occurs upon receipt of the product by the purchaser. We record terminaling, transportation, storage, and service revenues at the time the service is performed, and we record tank and other rentals over the term of the lease. Pursuant to terminaling services agreements with certain of our throughput customers, we are entitled to the volume of product gained resulting from differences in the measurement of product volumes received and distributed at our terminaling facilities. Such measurement differentials occur as the result of the inherent variances in measurement devices and methodology. We recognize as revenue the net proceeds from the sale of the product gained. Revenues for our water solutions segment are recognized upon receipt of 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. Amounts billed to customers for shipping and handling costs are included 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 concurrently and are entered into in contemplation of each other, we record the revenues for these transactions net of cost of sales.

Revenues during the year ended March 31, 2015 include $0.7 million associated with the amortization of a liability recorded in the acquisition accounting for an acquired business related to certain out-of-market revenue contracts.

Cost of Sales

We include in cost of sales all costs we incur to acquire products, including the costs of purchasing, terminaling, and transporting inventory, prior to delivery to our customers. Cost of sales does not include any depreciation of our property, plant and equipment. Cost of sales does include amortization of certain contract-based intangible assets of $7.8 million, $6.2 million, and $5.3 million during the years ended March 31, 2015, 2014, and 2013, respectively.

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Depreciation and Amortization

Depreciation and amortization in our consolidated statements of operations includes all depreciation of our property, plant and equipment and amortization of intangible assets other than debt issuance costs, for which the amortization is recorded to interest expense, and certain contract-based intangible assets, for which the amortization is recorded to cost of sales.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand and time deposits, and funds invested in highly liquid instruments with maturities of three months or less at the date of purchase. At times, certain account balances may exceed federally insured limits.

Supplemental Cash Flow Information

Supplemental cash flow information is as follows:

	Year Ended March 31, 2015	2014 (in thousands)	2013
Interest paid, exclusive of debt issuance costs and letter of credit fees	$ 90,556	$ 31,827	$ 27,384
Income taxes paid	$ 22,816	$ 1,639	$ 1,027

Cash flows from settlements of commodity derivative instruments are classified as cash flows from investing activities in our consolidated statements of cash flows, and adjustments to the fair value of commodity derivative instruments are included in the reconciliation of net income to net cash provided by operating activities.

Accounts Receivable and Concentration of Credit Risk

We operate in the United States and Canada. We grant unsecured credit to customers under normal industry standards and terms, and have established policies and procedures that allow for an evaluation of each customer s creditworthiness as well as general economic conditions. The allowance for doubtful accounts is based on our assessment of the collectability of customer accounts, which assessment considers the overall creditworthiness of customers and any specific disputes. Accounts receivable are considered past due or delinquent based on contractual terms. We write off accounts receivable against the allowance for doubtful accounts when collection efforts have been exhausted.

We execute netting agreements with certain customers to mitigate our credit risk. Receivables and payables are reflected at a net balance to the extent a netting agreement is in place and we intend to settle on a net basis.

Our accounts receivable consist of the following:

	March 31, 2015		March 31, 2014	
Segment	**Gross Receivable**	**Allowance for Doubtful Accounts**	**Gross Receivable**	**Allowance for Doubtful Accounts**
	(in thousands)			
Crude oil logistics	$ 600,896	$ 382	$ 410,746	$ 105
Water solutions	38,689	709	25,700	405
Liquids	99,699	1,133	169,827	617
Retail propane	55,147	1,619	75,606	1,667
Refined products and renewables	233,265	524	160,182	
Other	897		38,665	28
Total	$ 1,028,593	$ 4,367	$ 880,726	$ 2,822

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Changes in the allowance for doubtful accounts are as follows:

	Year Ended March 31, 2015	2014	2013
	(in thousands)		
Allowance for doubtful accounts, beginning of period	$ 2,822	$ 1,760	$ 818
Provision for doubtful accounts	3,838	2,172	1,315
Write off of uncollectible accounts	(2,293)	(1,110)	(373)
Allowance for doubtful accounts, end of period	$ 4,367	$ 2,822	$ 1,760

Sales of crude oil and natural gas liquids to our largest customer represented 16%, 10%, and 10% of consolidated total revenues for the years ended March 31, 2015, 2014, and 2013, respectively.

Inventories

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. In performing this analysis, we consider fixed-price forward sale 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. At March 31, 2015, our inventory values were reduced by $16.8 million of lower-of-cost-or-market adjustments.

Inventories consist of the following:

	March 31, 2015	2014
	(in thousands)	
Crude oil	$ 145,412	$ 156,473
Natural gas liquids		
Propane	44,535	85,159
Butane	8,668	15,106
Other	3,874	3,945
Refined products		
Gasoline	128,092	15,597
Diesel	59,097	7,612
Renewables	44,668	11,778
Other	7,416	14,490
Total	$ 441,762	$ 310,160

Investments in Unconsolidated Entities

In December 2013, as part of our acquisition of Gavilon Energy, we acquired a 50% interest in Glass Mountain and an interest in a limited liability company that owns an ethanol production facility in the Midwest. In June 2014, we acquired an interest in a limited liability company that operates a water supply company in the DJ Basin. On July 1, 2014, as part of our acquisition of TransMontaigne, we acquired the 2.0% general partner interest and a 19.7% limited partner interest in TLP, which owns a 42.5% interest in BOSTCO and a 50% interest in Frontera. We account for these investments using the equity method of accounting. Under the equity method, we do not report the individual assets and liabilities of these entities in our consolidated balance sheets; instead, our ownership interests are reported within investments in unconsolidated entities in our consolidated balance sheets. Under the equity method, the investment is recorded at acquisition cost, increased by our proportionate share of any earnings and additional capital contributions and decreased by our proportionate share of any losses, distributions paid, and amortization of any excess investment. Excess investment is the amount by which our total investment exceeds our proportionate share of the historical net book value of the net assets of the investee.

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Our investments in unconsolidated entities consist of the following:

Entity	Segment	March 31, 2015	2014
		(in thousands)	
Glass Mountain (1)	Crude oil logistics	$ 187,590	$ 186,488
BOSTCO (2)	Refined products and renewables	238,146	
Frontera (2)	Refined products and renewables	16,927	
Water supply company	Water solutions	16,471	
Ethanol production facility	Refined products and renewables	13,539	8,333
Total		$ 472,673	$ 194,821

(1) When we acquired Gavilon Energy, we recorded the investment in Glass Mountain at fair value. Our investment in Glass Mountain exceeds our share of the historical net book value of Glass Mountain s net assets by $76.7 million at March 31, 2015. This difference relates primarily to goodwill and customer relationships.

(2) When we acquired TransMontaigne, we recorded the investments in BOSTCO and Frontera at fair value. Our investments in BOSTCO and Frontera exceed our share of the historical net book value of BOSTCO s and Frontera s net assets by $14.7 million at March 31, 2015. This difference relates primarily to goodwill.

The following table summarizes the cumulative earnings (loss) from our unconsolidated entities and cumulative distributions received from our unconsolidated entities:

Entity	Cumulative Earnings (Loss) From Unconsolidated Entities	Cumulative Distributions Received From Unconsolidated Entities
	(in thousands)	
Glass Mountain	$ 3,704	$ 8,733
BOSTCO	4,505	9,725
Frontera	959	1,532
Water supply company	(29)	
Ethanol production facility	4,860	4,963

The summarized financial information of our unconsolidated entities was as follows:

Balance sheets:

	Water Supply	Ethanol Production

	Glass Mountain		BOSTCO	Frontera	Company	Facility	
				March 31,			
	2015	2014	2015	2015	2015	2015	2014
				(in thousands)			
Current assets	$ 8,456	$ 4,915	$ 13,710	$ 4,608	$ 3,160	$ 38,607	$ 43,522
Noncurrent assets	214,494	214,063	507,655	43,805	32,447	85,277	72,751
Current liabilities	1,080	3,181	11,189	1,370	644	15,755	17,707
Noncurrent liabilities	37	50			26,251	21,403	11,356

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Statements of operations:

	Glass Mountain		BOSTCO	Frontera	Water Supply Company	Ethanol Production Facility	
	Year Ended March 31,						
	2015	2014	2015	2015	2015	2015	2014
	(in thousands)						
Revenues	$ 37,539	$ 3,979	$ 45,067	$ 10,643	$ 8,326	$ 159,148	$ 61,929
Cost of sales	2,771					117,222	39,449
Net income (loss)	12,345	445	11,074	1,352	(104)	24,607	17,599

Other Noncurrent Assets

Other noncurrent assets consist of the following:

	March 31,	
	2015	2014
	(in thousands)	
Loan receivable (1)	$ 58,050	$
Linefill (2)	35,060	
Other	19,727	9,164
Total	$ 112,837	$ 9,164

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(1) Represents a loan receivable associated with our financing of the construction of a natural gas liquids facility to be utilized by a third party.

(2) Represents minimum volumes of crude oil we are required to leave on certain third-party owned pipelines under long-term shipment commitments. At March 31, 2015, linefill consisted of 487,104 barrels of crude oil.

Accrued Expenses and Other Payables

Accrued expenses and other payables consist of the following:

	March 31,	
	2015	2014
	(in thousands)	
Accrued compensation and benefits	$ 52,078	$ 45,006

Excise and other tax liabilities	43,847	13,421
Derivative liabilities	27,950	42,214
Accrued interest	23,065	18,668
Product exchange liabilities	15,480	3,719
Other	32,696	18,662
Total	$ 195,116	$ 141,690

Property, Plant and Equipment

We record property, plant and equipment at cost, less accumulated depreciation. Acquisitions and improvements are capitalized, and maintenance and repairs are expensed as incurred. As we dispose of assets, we remove the cost and related accumulated depreciation from the accounts, and any resulting gain or loss is included in loss on disposal or impairment of assets, net. We compute depreciation expense on a majority of our property, plant and equipment using the straight-line method over the estimated useful lives of the assets (see Note 5).

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We evaluate the carrying value of our property, plant and equipment 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 lower than its carrying value. In that event, we recognize a loss equal to the amount by which the carrying value exceeds the fair value of the asset group.

Intangible Assets

Our intangible assets include contracts and arrangements acquired in business combinations, including customer relationships, pipeline capacity rights, a water facility development agreement, executory contracts and other agreements, covenants not to compete, trade names, and customer commitments. In addition, we capitalize certain debt issuance costs incurred in our long-term debt arrangements. We amortize the majority of our intangible assets on a straight-line basis over the assets estimated useful lives (see Note 7). We amortize debt issuance costs over the terms of the related debt on a method that approximates the effective interest method.

We evaluate the carrying value of our 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 lower than its carrying value. In that event, we recognize a loss equal to the amount by which the carrying value exceeds the fair value of the asset group. When we cease to use an acquired trade name, we test the trade name for impairment using the relief from royalty method and we begin amortizing the trade name over its estimated useful life as a defensive asset.

Goodwill

Goodwill represents the excess of cost over the fair value of net assets of acquired businesses. Business combinations are accounted for using the acquisition method (see Note 4). We expect that substantially all of our goodwill at March 31, 2015 is deductible for income tax purposes.

Goodwill and intangible assets determined to have an indefinite useful life are not amortized, but instead are evaluated for impairment periodically. We evaluate goodwill and indefinite-lived intangible assets for impairment annually, or more often if events or circumstances indicate that the assets might be impaired. We perform the annual evaluation at January 1 of each year.

To perform this assessment, we consider qualitative factors to determine whether it is more likely than not that the fair value of each reporting unit exceeds its carrying amount. If we conclude that it is more likely than not that the fair value of a reporting unit exceeds its carrying amount, we perform the following two-step goodwill impairment test:

- In the first step of the goodwill impairment test, we compare the fair value of the reporting unit with its carrying amount, including goodwill. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is not considered impaired. If the carrying amount of a reporting unit exceeds its fair value, we perform the second step of the goodwill impairment test to measure the amount of impairment loss, if any.

- In the second step of the goodwill impairment test, we compare the implied fair value of reporting unit goodwill with the carrying amount of that goodwill. If the carrying amount of the reporting unit goodwill exceeds the implied fair value of that goodwill, an impairment loss is recognized in an amount equal to that excess.

Estimates and assumptions used to perform the impairment evaluation are inherently uncertain and can significantly affect the outcome of the analysis. The estimates and assumptions we used in the annual assessment for impairment of goodwill included market participant considerations and future forecasted operating results. Changes in operating results and other assumptions could materially affect these estimates. For our January 1, 2015 goodwill impairment assessment for our water solutions segment, we completed the first step of the impairment test and concluded that the fair value of the reporting unit exceeded the book value. For our other segments, based on our assessment of qualitative factors, we determined that the two-step impairment test was not required. Accordingly, we did not record any goodwill impairments during the years ended March 31, 2015, 2014, and 2013.

Product Exchanges

Quantities of products receivable or returnable under exchange agreements are reported within prepaid expenses and other current assets or within accrued expenses and other payables in our consolidated balance sheets. We estimate the value of product exchange assets and liabilities based on the weighted-average cost basis of the inventory we have delivered or will deliver on the exchange, plus or minus location differentials.

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Advance Payments Received from Customers

We record customer advances on product purchases as a liability in our consolidated balance sheets.

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.

On July 1, 2014, as part of our acquisition of TransMontaigne, we acquired a 19.7% limited partner interest in TLP. We have attributed net earnings allocable to TLP s limited partners to the controlling and noncontrolling interests based on the relative ownership interests in TLP as well as including certain adjustments related to our acquisition accounting. Earnings allocable to TLP s limited partners are net of the earnings allocable to TLP s general partner interest. The earnings allocable to TLP s general partner interest include the distributions of available cash (as defined by TLP s partnership agreement) attributable to the period to TLP s general partner interest and incentive distribution rights, net of adjustments for TLP s general partner s share of undistributed earnings. Undistributed earnings are allocated to TLP s limited partners and TLP s general partner interest based on their respective sharing of earnings or losses specified in TLP s partnership agreement, which is based on their ownership percentages of 98% and 2%, respectively.

Business Combination Measurement Period

We record the assets acquired and liabilities assumed in a business combination at their acquisition date fair values. 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. As described in Note 4, certain of our acquisitions during the year ended March 31, 2015 are still within this measurement period, and as a result, the acquisition date fair values we have recorded for the assets acquired and liabilities assumed are subject to change.

Also as described in Note 4, we made certain adjustments during the year ended March 31, 2015 to our estimates of the acquisition date fair values of assets acquired and liabilities assumed in business combinations that occurred during the year ended March 31, 2014. We retrospectively adjusted the March 31, 2014 consolidated balance sheet for these adjustments. Due to the immateriality of these adjustments, we did not retrospectively adjust our consolidated statement of operations for the year ended March 31, 2014 for these measurement period adjustments.

Recent Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2015-03, Simplifying the Presentation of Debt Issuance Costs. ASU No. 2015-03 requires that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The ASU is effective for the Partnership for both annual and interim periods beginning April 1, 2016 and requires retrospective application for all prior periods presented. Early adoption of this ASU is permitted for financial statements that have not been previously issued. We plan to adopt this ASU effective March 31, 2016, at which time we will begin presenting debt issuance costs as a reduction to long-term debt, rather than as an intangible asset.

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers. ASU No. 2014-09 will replace most existing revenue recognition guidance in GAAP. The core principle of this ASU is that an entity should recognize revenue for the transfer of goods or services equal to the amount that it expects to be entitled to receive for those goods or services. The ASU is effective for the Partnership beginning April 1, 2017, and allows for both full retrospective and modified retrospective (with cumulative effect) methods of adoption. We are in the process of determining the method of adoption and assessing the impact of this ASU on our consolidated financial statements.

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Note 3 Earnings Per Unit

Our earnings per common unit were computed as follows:

	Year Ended March 31,		
	2015	2014	2013
	(in thousands, except unit and per unit amounts)		
Net income attributable to parent equity	$ 16,661	$ 47,655	$ 47,940
Less: Net income allocated to general partner (1)	(45,679)	(14,148)	(2,917)
Less: Net loss (income) allocated to subordinated unitholders (2)	4,013	(1,893)	(5,506)
Net income (loss) allocated to common unitholders	$ (25,005)	$ 31,614	$ 39,517
Weighted average common units outstanding	86,359,300	61,970,471	41,353,574
Income (loss) per common unit - basic and diluted	$ (0.29)	$ 0.51	$ 0.96

(1) Net income allocated to the general partner includes distributions to which it is entitled as the holder of incentive distribution rights, which are described in Note 11.

(2) All outstanding subordinated units converted to common units in August 2014. Since the subordinated units did not share in the distribution of cash generated subsequent to June 30, 2014, we did not allocate any income or loss subsequent to that date to the subordinated unitholders. During the years ended March 31, 2014 and 2013, 5,919,346 subordinated units were outstanding. The income per subordinated unit was $0.32 and $0.93 for the years ended March 31, 2014 and 2013, respectively.

The restricted units described in Note 11 were antidilutive for the years ended March 31, 2015, 2014, and 2013, but could impact earnings per unit in future periods.

Note 4 Acquisitions

Year Ended March 31, 2015

As described in Note 2, 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 fair value of the assets acquired and liabilities assumed in a business combination. The business combinations for which this measurement period was still open as of March 31, 2015 are summarized below.

Natural Gas Liquids Storage Acquisition

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 U.S. markets and entered into a construction agreement to expand the storage capacity of the facility. We paid $97.6 million of cash, net of cash acquired, and issued 7,396,973 common units, valued at $218.5 million, in exchange for these assets and operations. The agreement for this acquisition contemplates post-closing payments for certain working capital items. We are in the process of identifying and determining the fair value of the assets acquired and liabilities assumed in this business combination. The estimates of fair value at March 31, 2015 are subject to change, and such changes could be material. We have preliminarily estimated the fair value of the assets acquired (and useful lives) and liabilities assumed as follows (in thousands):

Accounts receivable trade	$	42
Prepaid expenses and other current assets		600
Property, plant and equipment:		
Natural gas liquids terminal and storage assets (2 30 years)		62,205
Vehicles and railcars (3 25 years)		75
Land		68
Other		32
Construction in progress		19,525
Goodwill		151,853
Intangible assets:		
Customer relationships (15 years)		85,000
Non-compete agreements (10 years)		12,000
Accounts payable trade		(931)
Accrued expenses and other payables		(6,511)
Advance payments received from customers		(1,015)
Other noncurrent liabilities		(6,817)
Fair value of net assets acquired	$	316,126

Goodwill represents the excess of the consideration paid for the acquired business over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill primarily represents the value of synergies between the acquired business and the Partnership, the opportunity to use the acquired business as a platform for growth, and the acquired assembled workforce. We estimate that all of the goodwill will be deductible for federal income tax purposes.

We estimated the value of the customer relationship intangible asset using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

The acquisition method of accounting requires that executory contracts that are at unfavorable terms relative to current market conditions at the acquisition date be recorded as assets or liabilities in the acquisition accounting. Since certain natural gas liquids storage lease commitments were at unfavorable terms relative to acquisition-date market conditions, we recorded a liability of

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$12.8 million related to these lease commitments in the acquisition accounting, and we amortized $0.7 million of this balance as an increase to revenues during the year ended March 31, 2015. We will amortize the remainder of this liability over the term of the leases. The future amortization of this liability is shown below (in thousands):

Year Ending March 31,		
2016	$	5,807
2017		4,905
2018		1,306
2019		88

The operations of this acquisition have been included in our consolidated statements of operations since the acquisition date. Our consolidated statement of operations for the year ended March 31, 2015 includes revenues of $1.7 million that were generated by the operations of this business after we acquired them.

Bakken Water Solutions Facilities

On November 21, 2014, we completed the acquisition of two saltwater disposal facilities in the Bakken shale play in North Dakota for $34.6 million of cash.

We are in the process of identifying and determining the fair value of the assets acquired and liabilities assumed in this business combination. The estimates of fair value at March 31, 2015 are subject to change, and such changes could be material. We expect to complete this process prior to finalizing our financial statements for the three months ending September 30, 2015. We have preliminarily estimated the fair values of the assets acquired (and useful lives) and liabilities assumed as follows (in thousands):

Property, plant and equipment:		
Vehicles (10 years)	$	63
Water treatment facilities and equipment (5 40 years)		5,815
Buildings and leasehold improvements (3 7 years)		130
Land		100
Goodwill		6,560
Intangible asset:		
Customer relationships (6 years)		22,000
Other noncurrent liabilities		(68)
Fair value of net assets acquired	$	34,600

Goodwill represents the excess of the consideration paid for the acquired business over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill primarily represents the value of synergies between the acquired business and the Partnership and the opportunity to use the acquired business as a platform for growth. We estimate that all of the goodwill will be deductible for federal income tax purposes.

The operations of these water treatment and disposal facilities have been included in our consolidated statement of operations since their acquisition date. Our consolidated statement of operations for the year ended March 31, 2015 includes revenues of $3.6 million and operating income of $1.0 million that were generated by the operations of these facilities after we acquired them.

TransMontaigne Inc.

On July 1, 2014, we acquired TransMontaigne for $200.3 million of cash, net of cash acquired (including $174.1 million paid at closing and $26.2 million paid upon completion of the working capital settlement). As part of this transaction, we also purchased $380.4 million of inventory from the previous owner of TransMontaigne (including $346.9 million paid at closing and $33.5 million subsequently paid as the working capital settlement process progressed). The operations of TransMontaigne include the marketing of refined products. As part of this transaction, we acquired the 2.0% general partner interest, the incentive distribution rights, a 19.7% limited partner interest in TLP, and assumed certain terminaling service agreements with TLP from an affiliate of the previous owner of TransMontaigne.

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We are in the process of identifying and determining the fair value of the assets acquired and liabilities assumed in this business combination. The estimates of fair value at March 31, 2015 are subject to change, and such changes could be material. We expect to complete this process prior to finalizing our financial statements for the three months ending June 30, 2015. We have preliminarily estimated the fair values of the assets acquired (and useful lives) and liabilities assumed as follows (in thousands):

Cash and cash equivalents	$	1,469
Accounts receivable trade		197,829
Accounts receivable affiliates		528
Inventories		373,870
Prepaid expenses and other current assets		15,001
Property, plant and equipment:		
Refined products terminal assets and equipment (20 years)		399,323
Vehicles		1,698
Crude oil tanks and related equipment (20 years)		1,058
Information technology equipment		7,253
Buildings and leasehold improvements (20 years)		14,770
Land		70,529
Tank bottoms (indefinite life)		46,900
Other		15,534
Construction in progress		4,487
Goodwill		28,074
Intangible assets:		
Customer relationships (15 years)		76,100
Pipeline capacity rights (30 years)		87,618
Investments in unconsolidated entities		240,583
Other noncurrent assets		3,911
Accounts payable trade		(113,066)
Accounts payable affiliates		(69)
Accrued expenses and other payables		(78,427)
Advance payments received from customers		(1,919)
Long-term debt		(234,000)
Other noncurrent liabilities		(33,227)
Noncontrolling interests		(545,120)
Fair value of net assets acquired	$	580,707

Goodwill represents the excess of the consideration paid for the acquired business over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill primarily represents the value of synergies between the acquired business and the Partnership, the opportunity to use the acquired business as a platform for growth, and the acquired assembled workforce. We estimate that all of the goodwill will be deductible for federal income tax purposes.

We estimated the value of the customer relationship intangible asset using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

The intangible asset for pipeline capacity rights relates to capacity allocations on a third-party refined products pipeline. Demand for use of this pipeline exceeds the pipeline s capacity, and the limited capacity is allocated based on a shipper s historical shipment volumes.

The fair value of the noncontrolling interests was calculated by multiplying the closing price of TLP s common units on the acquisition date by the number of TLP common units held by parties other than us, adjusted for a lack-of-control discount.

In the acquisition accounting, we recorded a liability of $2.5 million related to certain crude oil contracts with terms that were unfavorable at current market conditions. We amortized this balance to cost of sales during the year ended March 31, 2015.

Employees of TransMontaigne participate in a plan whereby they are entitled to certain termination benefits in the event of a change in control of TransMontaigne and a subsequent change in job status. We recorded expense of $9.3 million during the year

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ended March 31, 2015 related to these termination benefits.

The operations of TransMontaigne have been included in our consolidated statements of operations since TransMontaigne was acquired on July 1, 2014. Our consolidated statement of operations for the year ended March 31, 2015 includes revenues of $3.9 billion and operating income of $36.3 million that were generated by the operations of TransMontaigne after we acquired them. We have not provided supplemental pro forma financial information as though the business combination had occurred on April 1, 2013 as the previous owner of TransMontaigne conducted trading operations, whereas we strive to generate more reliable and predictable cash flows. Because of the difference in strategies between the pre-acquisition and post-acquisition periods, the pre-acquisition operations of TransMontaigne have limited importance as an indicator of post-acquisition results.

Water Solutions Facilities

As described below, we are party to a development agreement that provides us a right to purchase water treatment and disposal facilities developed by the other party to the agreement, and we are also party to a solids facilities development agreement with this other party. During the year ended March 31, 2015, we purchased 16 water treatment and disposal facilities under this development agreement over the course of the year. We also purchased a 75% interest in one additional water treatment and disposal facility in July 2014 from a different seller. On a combined basis, we paid $190.0 million of cash and issued 1,322,032 common units, valued at $37.8 million, in exchange for these 17 facilities.

We are in the process of identifying and determining the fair value of the assets acquired and liabilities assumed in these business combinations. The estimates of fair value at March 31, 2015 are subject to change, and such changes could be material. We expect to complete this process prior to finalizing our financial statements for the three months ending December 31, 2015. We have preliminarily estimated the fair values of the assets acquired (and useful lives) and liabilities assumed as follows (in thousands):

Accounts receivable trade	$	939
Inventories		253
Prepaid expenses and other current assets		62
Property, plant and equipment:		
Water treatment facilities and equipment (5 40 years)		79,706
Buildings and leasehold improvements (3 7 years)		10,250
Land		3,109
Other (7 years)		129
Goodwill		132,770
Intangible asset:		
Customer relationships (4 years)		10,000
Other noncurrent assets		50
Accounts payable trade		(58)
Accrued expenses and other payables		(3,092)
Other noncurrent liabilities		(582)
Noncontrolling interest		(5,775)
Fair value of net assets acquired	$	227,761

Goodwill represents the excess of the consideration paid for the acquired business over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill primarily represents the value of synergies between the acquired business and the Partnership and the opportunity to use the acquired business as a platform for growth. We estimate that all of the goodwill will be deductible for federal income tax purposes.

The operations of these water treatment and disposal facilities have been included in our consolidated statement of operations since their acquisition date. Our consolidated statement of operations for the year ended March 31, 2015 includes revenues of $27.9 million and operating income of $10.5 million that were generated by the operations of these facilities after we acquired them.

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Retail Propane Acquisitions

During the year ended March 31, 2015, we completed eight acquisitions of retail propane businesses. On a combined basis, we paid $39.1 million of cash and issued 132,100 common units, valued at $3.7 million, in exchange for these assets and operations. The agreements for these acquisitions contemplate post-closing payments for certain working capital items. We are in the process of identifying and determining the fair value of the assets acquired and liabilities assumed in certain of these business combinations. The estimates of fair value at March 31, 2015 are subject to change, and such changes could be material. We expect to complete this process prior to finalizing our financial statements for the three months ending December 31, 2015. We have preliminarily estimated the fair value of the assets acquired (and useful lives) and liabilities assumed as follows (in thousands):

Accounts receivable trade	$	2,237
Inventories		771
Prepaid expenses and other current assets		110
Property, plant and equipment:		
Retail propane equipment (15 20 years)		13,177
Vehicles and railcars (5 7 years)		2,332
Buildings and leasehold improvements (30 years)		784
Land		655
Other (5 7 years)		116
Goodwill		8,097
Intangible assets:		
Customer relationships (10 15 years)		17,563
Non-compete agreements (5 7 years)		500
Trade names (3 12 years)		950
Accounts payable trade		(1,921)
Advance payments received from customers		(1,750)
Current maturities of long-term debt		(78)
Long-term debt, net of current maturities		(760)
Fair value of net assets acquired	$	42,783

Goodwill represents the excess of the consideration paid for the acquired businesses over the fair value of the individual assets acquired, net of liabilities assumed. Goodwill primarily represents the value of synergies between the acquired businesses and the Partnership, the opportunity to use the acquired businesses as a platform for growth, and the acquired assembled workforce. We estimate that all of the goodwill will be deductible for federal income tax purposes.

We estimated the value of the customer relationship intangible asset using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

Water Supply Company

On June 9, 2014, we paid cash of $15.0 million in exchange for an interest in a water supply company operating in the DJ Basin. The company holds exclusive rights to construct water disposal facilities on a dedicated acreage. We account for this investment using the equity method of accounting.

Year Ended March 31, 2014

Gavilon Energy

On December 2, 2013, we completed a business combination in which we acquired Gavilon Energy. We paid $832.4 million of cash, net of cash acquired, in exchange for these assets and operations.

The assets of Gavilon Energy include crude oil terminals in Oklahoma, Texas, and Louisiana, a 50% interest in Glass Mountain, which owns a crude oil pipeline that originates in western Oklahoma and terminates in Cushing, Oklahoma, 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.

During the year ended March 31, 2015, we completed the acquisition accounting for this business combination. The following table presents the final calculation of the fair values of the assets acquired (and useful lives) and liabilities assumed for this acquisition:

	Final	Estimated at March 31, 2014 (in thousands)	Change
Accounts receivable trade	$ 326,484	$ 349,529	$ (23,045)
Accounts receivable affiliates	2,564	2,564	
Inventories	107,430	107,430	
Prepaid expenses and other current assets	68,322	68,322	
Property, plant and equipment:			
Vehicles (3 years)	327	791	(464)
Crude oil tanks and related equipment (3 40 years)	83,797	77,429	6,368
Information technology equipment (3 7 years)	4,049	4,046	3
Buildings and leasehold improvements (3 40 years)	7,817	7,716	101
Land	6,427	6,427	
Tank bottoms (indefinite life)	16,930	15,230	1,700
Other (7 years)	162	170	(8)
Construction in progress	7,180	7,190	(10)
Goodwill (1)	342,769	359,169	(16,400)
Intangible assets:			
Customer relationships (10 20 years)	107,950	101,600	6,350
Lease agreements (1 5 years)	8,700	8,700	
Pipeline capacity rights (30 years)	7,800		7,800
Investments in unconsolidated entities	183,000	178,000	5,000
Other noncurrent assets	2,287	9,918	(7,631)
Accounts payable trade	(342,792)	(342,792)	
Accounts payable affiliates	(2,585)	(2,585)	
Accrued expenses and other payables	(49,447)	(70,999)	21,552
Advance payments received from customers	(10,667)	(10,667)	
Other noncurrent liabilities	(46,056)	(44,740)	(1,316)
Fair value of net assets acquired	$ 832,448	$ 832,448	$

(1) Of this goodwill, $302.8 million was allocated to our crude oil logistics segment, $36.0 million was allocated to our refined products and renewables segment, and $4.0 million was allocated to our liquids segment.

We estimated the value of the customer relationship intangible asset using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

The acquisition method of accounting requires that executory contracts that are at unfavorable terms relative to current market conditions at the acquisition date be recorded as assets or liabilities in the acquisition accounting. Since certain crude oil storage lease commitments were at unfavorable terms relative to acquisition-date market conditions, we recorded a liability of $15.9 million related to these lease commitments in the acquisition accounting, and we amortized $8.7 million of this balance as a reduction to cost of sales during the year ended March 31, 2015. We will amortize the remainder of this liability over the term of the leases. The future amortization of this liability is shown below (in thousands):

Year Ending March 31,		
2016	$	4,040
2017		360

Certain personnel who were employees of Gavilon Energy were entitled to a bonus, half of which was payable upon successful completion of the business combination and the remainder of which was paid in December 2014. We recorded this as compensation expense over the vesting period. We recorded expense of $6.5 million during the year ended March 31, 2015 related to these bonuses.

Oilfield Water Lines, LP

On August 2, 2013, we completed a business combination with entities affiliated with OWL, whereby we acquired water disposal and transportation assets in Texas. We issued 2,463,287 common units, valued at $68.6 million, and paid $167.7 million of cash, net of cash acquired, in exchange for OWL. During the year ended March 31, 2015, we completed the acquisition accounting for this business combination. The following table presents the final calculation of the fair values of the assets acquired (and useful lives) and liabilities assumed for this acquisition:

		Final		**Estimated at March 31, 2014**		**Change**
				(in thousands)		
Accounts receivable trade	$	6,837	$	7,268	$	(431)
Inventories		154		154		
Prepaid expenses and other current assets		402		402		
Property, plant and equipment:						
Vehicles (5 10 years)		8,143		8,157		(14)
Water treatment facilities and equipment (3 30 years)		23,173		23,173		
Buildings and leasehold improvements (7 30 years)		2,198		2,198		
Land		710		710		
Other (3 5 years)		53		53		
Goodwill		90,144		89,699		445
Intangible assets:						
Customer relationships (8 10 years)		110,000		110,000		
Non-compete agreements (3 years)		2,000		2,000		
Accounts payable trade		(6,469)		(6,469)		
Accrued expenses and other payables		(992)		(992)		
Other noncurrent liabilities		(64)		(64)		
Fair value of net assets acquired	$	236,289	$	236,289	$	

We estimated the value of the customer relationship intangible asset using the income approach, which uses valuation techniques to convert future amounts (for example, cash flows or earnings) to a single present amount (discounted). The measurement is based on the value indicated by current market expectations about those future amounts.

Other Water Solutions Acquisitions

During the year ended March 31, 2014, we completed two separate acquisitions of businesses to expand our water solutions operations in Texas. On a combined basis, we issued 222,381 common units, valued at $6.8 million, and paid $151.6 million of cash, net of cash acquired, in exchange for these assets and operations. During the year ended March 31, 2015, we completed the acquisition accounting for these business combinations. The following table presents the final calculation of the fair values of the assets acquired (and useful lives) and liabilities assumed for these acquisitions:

	Final	Estimated at March 31, 2014 (in thousands)	Change
Accounts receivable trade	$ 2,146	$ 2,146	$
Inventories	192	192	
Prepaid expenses and other current assets	62	61	1
Property, plant and equipment:			
Vehicles (5 10 years)	76	90	(14)
Water treatment facilities and equipment (3 30 years)	11,717	14,394	(2,677)
Buildings and leasehold improvements (7 30 years)	3,278	1,906	1,372
Land	207	206	1
Other (3 5 years)	12	12	
Goodwill	49,067	47,750	1,317
Intangible assets:			
Customer relationships (8 10 years)	72,000	72,000	
Trade names (indefinite life)	3,325	3,325	
Non-compete agreements (3 years)	260	260	
Water facility development agreement (5 years)	14,000	14,000	
Water facility option agreement	2,500	2,500	
Accounts payable trade	(119)	(119)	
Accrued expenses and other payables	(293)	(293)	
Other noncurrent liabilities	(64)	(64)	
Fair value of net assets acquired	$ 158,366	$ 158,366	$

As part of one of these business combinations, we entered into an option agreement with the seller of the business whereby we had the option to purchase a saltwater disposal facility that was under construction. We recorded an intangible asset of $2.5 million at the acquisition date related to this option agreement. On March 1, 2014, we purchased the saltwater disposal facility for additional cash consideration of $3.8 million.

In addition, as part of one of these business combinations, we entered into a development agreement that provides us a right to purchase water treatment and disposal facilities that may be developed by the seller through June 2018. On March 1, 2014, we purchased our first water treatment and disposal facility pursuant to the development agreement for $21.0 million.

During the year ended March 31, 2015, we completed the acquisition accounting for these business combinations. The following table presents the final calculation of the fair values of the assets acquired (and useful lives) and liabilities assumed for these acquisitions:

	Final	Estimated at March 31, 2014 (in thousands)	Change
Accounts receivable trade	$ 124	$ 245	$ (121)
Inventories	119	197	(78)
Property, plant and equipment:			
Water treatment facilities and equipment (3 30 years)	10,539	10,540	(1)
Buildings and leasehold improvements (7 30 years)	1,130	1,130	
Land	213	213	
Other (3 5 years)	1	1	
Goodwill	15,443	15,281	162
Accounts payable trade	(232)	(263)	31
Accrued expenses and other payables		(7)	7
Other noncurrent liabilities	(50)	(50)	
Fair value of net assets acquired	$ 27,287	$ 27,287	$

Crude Oil Logistics Acquisitions

During the year ended March 31, 2014, we completed two separate acquisitions of businesses to expand our crude oil logistics operations in Texas and Oklahoma. On a combined basis, we issued 175,211 common units, valued at $5.3 million, and paid $67.8 million of cash, net of cash acquired, in exchange for these assets and operations. During the year ended March 31, 2015, we completed the acquisition accounting for these business combinations. The following table presents the final calculation of the fair values of the assets acquired (and useful lives) and liabilities assumed for these acquisitions:

	Final	Estimated at March 31, 2014 (in thousands)	Change
Accounts receivable trade	$ 1,221	$ 1,235	$ (14)
Inventories	1,021	1,021	
Prepaid expenses and other current assets	58	54	4
Property, plant and equipment:			
Vehicles (5 10 years)	2,980	2,977	3
Crude oil tanks and related equipment (2 30 years)	3,822	3,462	360
Barges and towboats (20 years)	20,065	20,065	
Buildings and leasehold improvements (5 30 years)	58	280	(222)
Other (3 5 years)	57	53	4
Goodwill	30,730	37,867	(7,137)
Intangible assets:			
Customer relationships (3 years)	13,300	6,300	7,000
Non-compete agreements (3 years)	35	35	
Trade names (indefinite life)	530	530	
Accounts payable trade	(521)	(665)	144
Accrued expenses and other payables	(266)	(124)	(142)

Fair value of net assets acquired	$	73,090	$	73,090	$

Retail Propane and Liquids Acquisitions

During the year ended March 31, 2014, we completed four acquisitions of retail propane businesses and the acquisition of four natural gas liquids terminals. On a combined basis, we paid $21.9 million of cash to acquire these assets and operations. During the year ended March 31, 2015, we completed the acquisition accounting for these business combinations. The final calculation of the fair values of the assets acquired and liabilities assumed for these acquisitions did not materially change from the previous estimates of the fair values of the assets acquired and liabilities assumed for these acquisitions.

Note 5 Property, Plant and Equipment

Our property, plant and equipment consists of the following:

Description and Estimated Useful Lives		**March 31, 2015**		**2014**
		(in thousands)		
Natural gas liquids terminal and storage assets (2 30 years)	$	132,851	$	75,141
Refined products terminal assets and equipment (20 years)		403,609		
Retail propane equipment (2 30 years)		181,140		160,758
Vehicles and railcars (3 25 years)		180,679		152,187
Water treatment facilities and equipment (3 40 years)		317,317		178,307
Crude oil tanks and related equipment (2 40 years)		109,909		101,853
Barges and towboats (5 40 years)		59,848		52,217
Information technology equipment (3 7 years)		34,915		20,771
Buildings and leasehold improvements (3 40 years)		98,989		61,255
Land		107,098		30,242
Tank bottoms		62,656		15,103
Other (3 30 years)		34,415		17,337
Construction in progress		96,922		80,241
		1,820,348		945,412
Accumulated depreciation		(202,959)		(109,564)
Net property, plant and equipment	$	1,617,389	$	835,848

Depreciation expense was $105.7 million, $59.9 million and $39.2 million during the years ended March 31, 2015, 2014 and 2013, respectively. During the years ended March 31, 2015 and 2014, we capitalized $0.1 million and $0.7 million of interest expense, respectively. We did not capitalize any interest expense during the year ended March 31, 2013. Product volumes required for the operation of storage tanks, known as tank bottoms, are recorded at historical cost. We recover tank bottoms when we no longer use the storage tanks or the storage tanks are removed from service.

The following table summarizes the tank bottoms included in the table above at March 31, 2015 (in thousands):

Product	**Volume**		**Book Value**
Gasoline (barrels)	219	$	25,710
Crude oil (barrels)	184		16,835

Diesel (barrels)	124	15,153
Renewables (barrels)	41	4,220
Other	504	738
Total		$ 62,656

Note 6 Goodwill

The changes in the balance of goodwill were as follows:

	Year Ended March 31, 2015	2014 (in thousands)	2013
Beginning of period, as retrospectively adjusted	$ 1,085,393	$ 555,220	$ 167,245
Acquisitions (Note 4)	327,350	530,173	387,975
Disposals (Note 14)	(9,982)		
End of period, as retrospectively adjusted	$ 1,402,761	$ 1,085,393	$ 555,220

Goodwill by reportable segment is as follows:

	March 31, 2015	March 31, 2014
	(in thousands)	
Crude oil logistics	$ 579,846	$ 579,846
Water solutions	401,656	264,127
Liquids	234,803	91,135
Retail propane	122,382	114,285
Refined products and renewables	64,074	36,000
Total	$ 1,402,761	$ 1,085,393

Note 7 Intangible Assets

Our intangible assets consist of the following:

		March 31, 2015		March 31, 2014	
	Amortizable Lives	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
		(in thousands)			
Amortizable					
Customer relationships	3 20 years	$ 921,418	$ 159,215	$ 710,755	$ 83,261
Pipeline capacity rights	30 years	119,636	2,571	7,800	
Water facility development agreement	5 years	14,000	4,900	14,000	2,100
Executory contracts and other agreements	2 10 years	23,920	18,387	23,920	13,190
Non-compete agreements	2 10 years	26,662	10,408	14,161	6,388
Trade names	2 12 years	15,439	7,569	15,489	3,081
Debt issuance costs	5 10 years	55,165	17,467	44,089	8,708
Total amortizable		1,176,240	220,517	830,214	116,728
Non-amortizable					
Customer commitments		310,000			
Trade names		22,620		22,620	
Total non-amortizable		332,620		22,620	
Total		$ 1,508,860	$ 220,517	$ 852,834	$ 116,728

The weighted-average remaining amortization period for intangible assets is approximately 12 years.

Amortization expense is as follows:

	Year Ended March 31,		
Recorded In	**2015**	**2014**	**2013**
	(in thousands)		
Depreciation and amortization	$ 88,262	$ 60,855	$ 29,657
Cost of sales	7,767	6,172	5,285

Interest expense		8,759		5,727		3,375
Loss on early extinguishment of debt						5,769
Total	$	104,788	$	72,754	$	44,086

Expected amortization of our intangible assets, exclusive of assets that are not yet amortizable, is as follows (in thousands):

Year Ending March 31,		
2016	$	111,356
2017		104,633
2018		100,654
2019		91,799
2020		84,791
Thereafter		462,490
Total	$	955,723

Note 8 Long-Term Debt

Our long-term debt consists of the following:

	March 31, 2015		2014	
	(in thousands)			
Revolving credit facility				
Expansion capital borrowings	$	702,500	$	532,500
Working capital borrowings		688,000		389,500
5.125% Notes due 2019		400,000		
6.875% Notes due 2021		450,000		450,000
6.650% Notes due 2022		250,000		250,000
TLP credit facility		250,000		
Other long-term debt		9,271		14,914
		2,749,771		1,636,914
Less: Current maturities		4,472		7,080
Long-term debt	$	2,745,299	$	1,629,834

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, 2015, our Revolving Credit Facility had a total capacity of $2.296 billion.

The Expansion Capital Facility had a total capacity of $858.0 million for cash borrowings at March 31, 2015. At that date, we had outstanding borrowings of $702.5 million on the Expansion Capital Facility. The Working Capital Facility had a total capacity of $1.438 billion for cash borrowings and letters of credit at March 31, 2015. At that date, we had outstanding borrowings of $688.0 million and outstanding letters of credit of $108.6 million on 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.

All borrowings under the Credit Agreement bear interest, at our option, at (i) an alternate base rate plus a margin of 0.50% to 1.50% per annum or (ii) an adjusted LIBOR rate plus a margin of 1.50% to 2.50% per annum. The applicable margin is determined based on our consolidated leverage ratio, as defined in the Credit Agreement. At March 31, 2015, all borrowings under the Credit Agreement were LIBOR borrowings with an interest rate at March 31, 2015 of 2.18%, calculated as the LIBOR rate of 0.18% plus a margin of 2.0%. At March 31, 2015, the interest rate in effect on letters of credit was 2.25%. Commitment fees are charged at a rate ranging from 0.38% to 0.50% on any unused capacity.

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The Credit Agreement is secured by substantially all of our assets. The Credit Agreement specifies that our leverage ratio, as defined in the Credit Agreement, cannot exceed 4.25 to 1 at any quarter end. The leverage coverage ratio in our Credit Agreement excludes TLP s debt. At March 31, 2015, our leverage ratio was approximately 3.2 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, 2015, our interest coverage ratio was approximately 5.9 to 1.

The Credit Agreement contains various customary representations, warranties, and additional covenants, including, without limitation, limitations on fundamental changes and limitations on indebtedness and liens. Our obligations under the Credit Agreement may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) a breach by the Partnership or its subsidiaries of any material representation or warranty or any covenant made in the Credit Agreement, or (iii) certain events of bankruptcy or insolvency.

At March 31, 2015, 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). We received net proceeds of $393.5 million, after the initial purchasers discount of $6.0 million and offering costs of $0.5 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 prior to the maturity date, although we would be required to pay a premium for early redemption.

The Partnership and NGL Energy Finance Corp. are co-issuers of the 2019 Notes, and the obligations under the 2019 Notes are guaranteed by certain of our existing and future restricted subsidiaries that incur or guarantee indebtedness under certain of our other indebtedness, including the Revolving Credit Facility. The indenture governing the 2019 Notes contains various customary covenants, including, without limitation, limitations on fundamental changes and limitations on indebtedness and liens. Our obligations under the indenture may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) experiencing an event of default on certain other debt agreements, or (iii) certain events of bankruptcy or insolvency.

At March 31, 2015, 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). We received net proceeds of $438.4 million, after the initial purchasers discount of $10.1 million and offering costs of $1.5 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 prior to the maturity date, although we would be required to pay a premium for early redemption.

The Partnership and NGL Energy Finance Corp. are co-issuers of the 2021 Notes, and the obligations under the 2021 Notes are guaranteed by certain of our existing and future restricted subsidiaries that incur or guarantee indebtedness under certain of our other indebtedness, including the Revolving Credit Facility. The indenture governing the 2021 Notes contains various customary covenants, including, without limitation, limitations on fundamental changes and limitations on indebtedness and liens. Our obligations under the indenture may be accelerated following certain events of default (subject to applicable cure periods), including, without limitation, (i) the failure to pay principal or interest when due, (ii) experiencing an event of default on certain other debt agreements, or (iii) certain events of bankruptcy or insolvency.

At March 31, 2015, 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. 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.

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The Note Purchase Agreement contains various customary representations, warranties, and additional covenants that, among other things, limit our ability to (subject to certain exceptions): (i) incur additional debt, (ii) pay dividends and make other restricted payments, (iii) create or permit certain liens, (iv) create or permit restrictions on the ability of certain of our subsidiaries to pay dividends or make other distributions to us, (v) enter into transactions with affiliates, (vi) enter into sale and leaseback transactions and (vii) consolidate or merge or sell all or substantially all or any portion of our assets. In addition, the Note Purchase Agreement contains similar leverage ratio and interest coverage ratio requirements to those of our Credit Agreement, which is described above.

The Note Purchase Agreement provides for customary events of default that include, among other things (subject in certain cases to customary grace and cure periods): (i) nonpayment of principal or interest, (ii) breach of certain covenants contained in the Note Purchase Agreement or the 2022 Notes, (iii) failure to pay certain other indebtedness or the acceleration of certain other indebtedness prior to maturity if the total amount of such indebtedness unpaid or accelerated exceeds $10.0 million, (iv) the rendering of a judgment for the payment of money in excess of $10.0 million, (v) the failure of the Note Purchase Agreement, the 2022 Notes, or the guarantees by the subsidiary guarantors to be in full force and effect in all material respects and (vi) certain events of bankruptcy or insolvency. Generally, if an event of default occurs (subject to certain exceptions), the trustee or the holders of at least 51% in aggregate principal amount of the then outstanding 2022 Notes of any series may declare all of the 2022 Notes of such series to be due and payable immediately.

At March 31, 2015, we were in compliance with the covenants under the Note Purchase Agreement.

TLP Credit Facility

TLP is party to a credit agreement with a syndicate of banks that provides for a revolving credit facility (the TLP Credit Facility). The TLP Credit Facility provides for a maximum borrowing line of credit equal to the lesser of (i) $400 million and (ii) 4.75 times Consolidated EBITDA (as defined in the TLP Credit Facility). The terms of the TLP Credit Facility include covenants that restrict TLP s ability to make cash distributions, acquisitions and investments, including investments in joint ventures. TLP may make distributions of cash to the extent of TLP s available cash as defined in TLP s partnership agreement. TLP may make acquisitions and investments that meet the definition of permitted acquisitions ; other investments which may not exceed 5% of consolidated net tangible assets ; and additional future permitted JV investments up to $125 million, which may include additional investments in BOSTCO. The principal balance of loans and any accrued and unpaid interest are due and payable in full on the maturity date of July 31, 2018.

The following table summarizes our basis in the assets and liabilities of TLP at March 31, 2015, inclusive of the impact of our acquisition accounting for the business combination with TransMontaigne (in thousands):

Cash and cash equivalents	$	918
Accounts receivable trade		9,069
Accounts receivable affiliates		583
Inventories		1,361
Prepaid expenses and other current assets		1,410
Property, plant and equipment, net		475,506
Goodwill		28,074
Intangible assets, net		72,295
Investments in unconsolidated affiliates		255,073

Other noncurrent assets		2,458
Accounts payable trade		(6,565)
Accounts payable affiliates		(76)
Net intercompany payable		(1,965)
Accrued expenses and other payables		(8,715)
Advanced payments received from customers		(146)
Long-term debt		(250,000)
Other noncurrent liabilities		(3,541)
Net assets	$	575,739

TLP may elect to have loans under the TLP Credit Facility bear interest either (i) at a rate of LIBOR plus a margin ranging from 2% to 3% depending on the total leverage ratio then in effect, or (ii) at the base rate plus a margin ranging from 1% to 2% depending on the total leverage ratio then in effect. TLP also pays a commitment fee on the unused amount of commitments, ranging

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from 0.375% to 0.5% per annum, depending on the total leverage ratio then in effect. For the period from July 1, 2014 to March 31, 2015, the weighted-average interest rate on borrowings under the TLP Credit Facility was approximately 2.10%. TLP s obligations under the TLP Credit Facility are secured by a first priority security interest in favor of the lenders in the majority of TLP s assets, including TLP s investments in unconsolidated entities. At March 31, 2015, TLP had outstanding borrowings under the TLP Credit Facility of $250 million and no outstanding letters of credit.

The TLP Credit Facility also contains customary representations and warranties (including those relating to organization and authorization, compliance with laws, absence of defaults, material agreements and litigation) and customary events of default (including those relating to monetary defaults, covenant defaults, cross defaults and bankruptcy events). The primary financial covenants contained in the TLP Credit Facility are (i) a total leverage ratio test (not to exceed 4.75 times), (ii) a senior secured leverage ratio test (not to exceed 3.75 times) in the event TLP issues senior unsecured notes, and (iii) a minimum interest coverage ratio test (not less than 3.0 times). These financial covenants are based on a defined financial performance measure within the TLP Credit Facility known as Consolidated EBITDA.

TLP s Credit Facility is non-recourse to NGL.

Other Long-Term Debt

We have executed various noninterest bearing notes payable, primarily related to non-compete agreements entered into in connection with acquisitions of businesses. We also have certain notes payable related to equipment financing.

Debt Maturity Schedule

The scheduled maturities of our long-term debt are as follows at March 31, 2015:

Year Ending March 31,	Revolving Credit Facility	2019 Notes	2021 Notes	2022 Notes (in thousands)	TLP Credit Facility	Other Long-Term Debt	Total
2016	$	$	$	$	$	$ 4,473	$ 4,473
2017						2,567	2,567
2018				25,000		1,626	26,626
2019	1,390,500			50,000	250,000	362	1,690,862
2020		400,000		50,000		105	450,105
Thereafter			450,000	125,000		138	575,138
Total	$ 1,390,500	$ 400,000	$ 450,000	$ 250,000	$ 250,000	$ 9,271	$ 2,749,771

Previous Credit Facility

On June 19, 2012, we made a principal payment of $306.8 million to retire a then-existing revolving credit facility. Upon retirement of this facility, we wrote off the portion of the debt issuance cost intangible asset that had not yet been amortized. This expense is reported as Loss on early extinguishment of debt in our consolidated statement of operations for the year ended March 31, 2013.

Note 9 Income Taxes

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 2011 to 2014 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.

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We acquired TransMontaigne Inc. on July 1, 2014. TransMontaigne Inc. and certain of its subsidiaries were taxable corporations until we converted them to non-taxable limited liability companies on December 31, 2014. The following table is a rollforward of the income tax liability associated with these entities (in thousands):

Acquisition-date deferred tax liability	$	28,530
Income tax benefit (July 1, 2014 to December 31, 2014)		(6,276)
Tax payments		(21,397)
Current tax liability at March 31, 2015	$	857

A publicly traded partnership is required to generate at least 90% of its gross income (as defined for federal income tax purposes) from certain qualifying sources. Income generated by our taxable corporate subsidiaries is excluded from this qualifying income calculation. Although we routinely generate income outside of our corporate subsidiaries that is non-qualifying, we believe that at least 90% of our gross income has been qualifying income for each of the calendar years since our IPO.

We evaluate uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, we determine whether it is more likely than not that the tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. We had no material uncertain tax positions that required recognition in our consolidated financial statements at March 31, 2015 or 2014.

Note 10 Commitments and Contingencies

Legal Contingencies

We are party to various claims, legal actions, and complaints arising in the ordinary course of business. In the opinion of our management, the ultimate resolution of these claims, legal actions, and complaints, after consideration of amounts accrued, insurance coverage, and other arrangements, will not have a material adverse effect on our consolidated financial position, results of operations or cash flows. However, the outcome of such matters is inherently uncertain, and estimates of our liabilities may change materially as circumstances develop.

Customer Dispute

A customer of our crude oil logistics segment disputed the transportation rate schedule we used to bill the customer for services that we provided from November 2012 through February 2013, which was the same rate schedule that Pecos used to bill the customer from April 2011 through October 2012 (prior to our November 1, 2012 acquisition of Pecos). During August 2013, the customer notified us that it intended to withhold payment due for services performed by us during the period from June 2013 through August 2013, pending resolution of the dispute, although the customer did not dispute the validity of the amounts billed for services performed during this time frame.

During September 2014, we reached an agreement with the former customer whereby the former customer agreed to pay us an agreed-upon amount to dismiss its claims against us, in return for which we agreed to dismiss our claims against the former customer. We did not record a gain or loss upon settlement, as the amount we received approximated the amount we had recorded as receivable from the customer.

Contractual Disputes

During the year ended March 31, 2015, we settled two separate contractual disputes and recorded $5.5 million of proceeds to other income in our consolidated statement of operations. 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.

Environmental Matters

Our operations are subject to extensive federal, state, and local environmental laws and regulations. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in our business, and there can be no assurance that significant costs will not be incurred. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs. Accordingly, we have adopted policies, practices, and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use, and

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disposal of hazardous materials designed to prevent material environmental or other damage, and to limit the financial liability that could result from such events. However, some risk of environmental or other damage is inherent in our business.

Asset Retirement Obligations

We have recorded a liability of $3.9 million at March 31, 2015 for asset retirement obligations. This liability is related to facilities for which we have contractual and regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are retired.

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.

Operating Leases

We have executed various noncancelable operating lease agreements for product storage, office space, vehicles, real estate, railcars, and equipment. Future minimum lease payments under these agreements at March 31, 2015 are as follows (in thousands):

Year Ending March 31,		
2016	$	119,817
2017		102,394
2018		87,302
2019		63,205
2020		53,423
Thereafter		115,704
Total	$	541,845

Rental expense relating to operating leases was $125.5 million, $98.3 million, and $84.2 million during the years ended March 31, 2015, 2014, and 2013, respectively.

Pipeline Capacity Agreements

We have executed noncancelable agreements with crude oil and refined products pipeline operators, which guarantee us minimum monthly shipping capacity on the pipelines. In exchange, we are obligated to pay the minimum shipping fees in the event actual shipments are less than our allotted capacity. Future minimum throughput payments under these agreements at March 31, 2015 are as follows (in thousands):

Year Ending March 31,		
2016	$	122,052
2017		81,935
2018		82,016
2019		81,222
2020		53,511
Thereafter		90,972
Total	$	511,708

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Sales and Purchase Contracts

We have entered into sales and purchase contracts for products to be delivered in future periods for which we expect the parties to physically settle the contracts with inventory. At March 31, 2015, we had the following such commitments outstanding:

	Volume		Value
	(in thousands)		
Purchase commitments:			
Natural gas liquids fixed-price (gallons)	57,792	$	35,476
Natural gas liquids index-price (gallons)	659,603		352,563
Crude oil index-price (barrels)	8,450		375,699
Sale commitments:			
Natural gas liquids fixed-price (gallons)	104,153		77,674
Natural gas liquids index-price (gallons)	223,234		184,866
Crude oil fixed-price (barrels)	1,580		79,242
Crude oil index-price (barrels)	6,684		321,863

We account for the contracts shown in the table above as normal purchases and normal sales. 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. Contracts in the table above may have offsetting derivative contracts (described in Note 12) or inventory positions (described in Note 2).

Certain other forward purchase and sale contracts do not qualify for the normal purchase and normal sale election. These contracts are recorded at fair value in our consolidated balance sheet and are not included in the table above. These contracts are included in the derivative disclosures in Note 12, and represent $33.2 million of our prepaid expenses and other current assets and $26.6 million of our accrued expenses and other payables at March 31, 2015.

Note 11 Equity

Partnership Equity

The Partnership s equity consists of a 0.1% general partner interest and a 99.9% limited partner interest, which consists of common units. Prior to August 2014, the Partnership s limited partner interest also included subordinated units. The subordination period ended in August 2014, at which time all remaining subordinated units were converted into common units on a one-for-one basis. Our general partner is not obligated to make any additional capital contributions or to guarantee or pay any of our debts and obligations.

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Common Units Issued in Business Combinations

We issued common units as partial consideration for several acquisitions. These are summarized below:

March 31, 2013	
High Sierra combination	20,703,510
Retail propane combinations	850,676
Crude oil logistics and water solutions combinations	516,978
Pecos combination	1,834,414
Third Coast combination	344,680
Total	24,250,258
March 31, 2014	
Water solutions combinations	222,381
Crude oil logistics combinations	175,211
OWL combination	2,463,287
Total	2,860,879
March 31, 2015	
Retail propane combinations	132,100
Natural gas liquids storage combination	7,396,973
Water solutions combinations	1,322,032
Total	8,851,105

In connection with the completion of certain of these acquisitions, we amended our registration rights agreement, which provides for certain registration rights for certain holders of our common units.

Equity Issuances

The following table summarizes our equity issuances for fiscal years 2014 and 2015 (in millions, except unit amounts). There were no equity issuances during fiscal year 2013.

Issuance Date	Type of Offering	Number of Common Units Issued	Gross Proceeds	Underwriting Discounts and Commissions	Offering Costs	Net Proceeds
March 11, 2015	Public Offering	6,250,000	$ 172.3	$ 1.4	$ 0.2	$ 170.7
June 23, 2014	Public Offering	8,767,100	383.2	12.3	0.5	370.4
December 2, 2013	Private Placement	8,110,848	240.0		4.9	235.1
September 25, 2013	Public Offering	4,100,000	132.8	5.0	0.2	127.6
July 5, 2013	Public Offering	10,350,000	300.2	12.0	0.7	287.5

Our Distribution Policy

Our general partner has adopted a cash distribution policy that requires us to pay a quarterly distribution to unitholders as of the record date to the extent we have sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to the general partner and its affiliates, referred to as available cash. 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	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 following table summarizes the distributions declared subsequent to our IPO:

Date Declared	Record Date	Date Paid	Amount Per Unit	Amount Paid To Limited Partners (in thousands)	Amount Paid To General Partner (in thousands)
July 25, 2011	August 3, 2011	August 12, 2011	$ 0.1669	$ 2,467	$ 3
October 21, 2011	October 31, 2011	November 14, 2011	0.3375	4,990	5
January 24, 2012	February 3, 2012	February 14, 2012	0.3500	7,735	10
April 19, 2012	April 30, 2012	May 15, 2012	0.3625	9,165	10
July 24, 2012	August 3, 2012	August 14, 2012	0.4125	13,574	134
October 17, 2012	October 29, 2012	November 14, 2012	0.4500	22,846	707
January 24, 2013	February 4, 2013	February 14, 2013	0.4625	24,245	927
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

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Several of our business combination agreements contained provisions that temporarily limited the distributions to which the newly issued units were entitled. The following table summarizes the number of equivalent units that were not eligible to receive a distribution on each of the record dates:

Record Date	Equivalent Units Not Eligible
October 31, 2011	4,000,000
February 3, 2012	7,117,031
April 30, 2012	3,932,031
August 3, 2012	17,862,470
October 29, 2012	516,978
February 4, 2013	1,202,085
November 4, 2013	979,886
February 6, 2015	132,100
May 5, 2015	8,352,904

TLP s Distribution Policy

TLP s partnership agreement requires it to pay a quarterly distribution to unitholders as of the record date to the extent TLP has sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to TLP s general partner and its affiliates, referred to as available cash. TLP s general partner will also receive, in addition to distributions on its 2.0% general partner interest, additional distributions based on the level of distributions to the limited partners. These distributions are referred to as incentive distributions. TLP s general partner currently holds the incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in TLP s partnership agreement.

The following table illustrates the percentage allocations of available cash from operating surplus between TLP s unitholders and TLP s general partner based on the specified target distribution levels. The amounts set forth under Marginal Percentage Interest In Distributions are the percentage interests of TLP s general partner and TLP s unitholders in any available cash from operating surplus TLP distributes up to and including the corresponding amount in the column Total Quarterly Distribution Per Unit, until available cash from operating surplus TLP distributes reaches the next target distribution level, if any. The percentage interests shown for TLP s unitholders and TLP s 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 TLP s general partner include its 2.0% general partner interest, and assume that TLP s general partner has contributed any additional capital necessary to maintain its 2.0% general partner interest and has not transferred its incentive distribution rights.

	Total Quarterly Distribution Per Unit					Marginal Percentage Interest In Distributions	
						Unitholders	General Partner
Minimum quarterly distribution					$ 0.40	98%	2%
First target distribution	above	$	0.40	up to	$ 0.44	98%	2%
Second target distribution	above	$	0.44	up to	$ 0.50	85%	15%
Third target distribution	above	$	0.50	up to	$ 0.60	75%	25%
Thereafter	above	$	0.60			50%	50%

The following table summarizes the distributions declared by TLP subsequent to 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):

Date Declared	Record Date	Date Paid	Amount Per Unit	Amount Paid To NGL (in thousands)	Amount Paid To Other Partners (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

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Equity-Based Incentive Compensation

Our general partner has adopted a long-term incentive plan (LTIP), which allows for the issuance of equity-based compensation. Our general partner has granted certain restricted units to employees and directors, which vest in tranches, subject to the continued service of the recipients. The awards may also vest in the event of a change in control, at the discretion of the board of directors. No distributions accrue to or are paid on the restricted units during the vesting period.

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 following table summarizes the Service Award activity during the years ended March 31, 2015, 2014 and 2013:

Unvested Service Award units at March 31, 2012	
Units granted	1,684,400
Units vested and issued	(156,802)
Units withheld for employee taxes	(61,698)
Units forfeited	(21,000)
Unvested Service Award units at March 31, 2013	1,444,900
Units granted	494,000
Units vested and issued	(296,269)
Units withheld for employee taxes	(122,531)
Units forfeited	(209,000)
Unvested Service Award units at March 31, 2014	1,311,100
Units granted	2,093,139
Units vested and issued	(586,010)
Units withheld for employee taxes	(354,829)
Units forfeited	(203,000)
Unvested Service Award units at March 31, 2015	2,260,400

The scheduled vesting of our Service Award units is summarized below:

[redacted]	
2016	739,500
[redacted]	
2018	679,200
[redacted]	
2020	20,000
[redacted]	

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 distribution growth.

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We estimate that the future expense we will record on the unvested Service Award units at March 31, 2015 will be as follows (in thousands), after taking into consideration an estimate of forfeitures of approximately 129,000 units. For purposes of this calculation, we used the closing price of our common units on March 31, 2015, which was $26.23.

Year Ending March 31,		
2016	$	26,304
2017		16,938
2018		5,369
2019		1,033
2020		105
Total	$	49,749

Following is a rollforward of the liability related to the Service Award units, which is reported within accrued expenses and other payables in our consolidated balance sheets (in thousands):

Balance at March 31, 2012	$	
Expense recorded		10,138
Value of units vested and issued		(3,657)
Taxes paid on behalf of participants		(1,438)
Balance at March 31, 2013		5,043
Expense recorded		17,804
Value of units vested and issued		(9,085)
Taxes paid on behalf of participants		(3,750)
Balance at March 31, 2014		10,012
Expense recorded		32,767
Value of units vested and issued		(23,134)
Taxes paid on behalf of participants		(13,491)
Balance at March 31, 2015	$	6,154

The weighted-average fair value of the Service Award units at March 31, 2015 was $22.61 per common unit, which was calculated as the closing price of the common units on March 31, 2015, adjusted 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 and assumptions that a market participant might make about future distribution growth.

During April 2015, our general partner granted Performance Award units to certain employees. The maximum number of units that could vest on these Performance Awards for each vesting tranche is summarized below:

Vesting Date	Maximum Performance Award Units
July 1, 2015	681,382
July 1, 2016	679,382
July 1, 2017	641,382
Total	2,002,146

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 percentage of the maximum Performance Award units that will vest will depend on the percentage of entities in the Index that NGL outperforms, as summarized in the table below:

Percentage of Entities in the Index that NGL Outperforms	Percentage of Maximum Performance Award Units to Vest
Less than 50%	0%
50% 75%	25% 50%
75% 90%	50% 100%
Greater than 90%	100%

Beginning in fiscal year 2016, we will record the expense for each of the three tranches on a straight-line basis over the period beginning with the April 2015 grant date and ending with the vesting date. At each balance sheet date, we will adjust the cumulative expense recorded using the estimated fair value of the awards at the balance sheet date. We will calculate the fair value of the awards using a Monte Carlo simulation.

The number of common units that may be delivered pursuant to awards under the LTIP is limited to 10% of the issued and outstanding common units. The maximum number of units deliverable under the plan 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. Units withheld to satisfy tax withholding obligations are not considered to be delivered under the LTIP. In addition, when an award is forfeited, canceled, exercised, paid or otherwise terminates or expires without the delivery of units, the units subject to such award are again available for new awards under the LTIP. At March 31, 2015, approximately 7.1 million common units remain available for issuance under the LTIP.

Note 12 Fair Value of Financial Instruments

Our cash and cash equivalents, accounts receivable, accounts payable, accrued expenses, and other current assets and liabilities (excluding derivative instruments) are carried at amounts which reasonably approximate their fair values due to their short-term nature.

Commodity Derivatives

The following table summarizes the estimated fair values of our commodity derivative assets and liabilities reported in our consolidated balance sheet at March 31, 2015:

	Derivative Assets	Derivative Liabilities
	(in thousands)	
Level 1 measurements	$ 83,779	$ (3,969)
Level 2 measurements	34,963	(28,764)
	118,742	(32,733)

Netting of counterparty contracts (1)		(1,804)		1,804
Cash collateral provided (held)		(56,660)		2,979
Commodity derivatives on consolidated balance sheet	$	60,278	$	(27,950)

(1) Relates to commodity derivative assets and liabilities that are expected to be net settled on an exchange or through a master netting arrangement with the counterparty.

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The following table summarizes the estimated fair values of our commodity derivative assets and liabilities reported in our consolidated balance sheet at March 31, 2014:

	Derivative Assets	Derivative Liabilities
	(in thousands)	
Level 1 measurements	$ 4,990	$ (3,258)
Level 2 measurements	49,605	(43,303)
	54,595	(46,561)
Netting of counterparty contracts (1)	(4,347)	4,347
Net cash collateral provided	456	
Commodity derivatives on consolidated balance sheet	$ 50,704	$ (42,214)

(1) Relates to commodity derivative assets and liabilities that are expected to be net settled on an exchange or through a master netting arrangement with the counterparty.

Our commodity derivative assets and liabilities are reported in the following accounts in our consolidated balance sheets:

	March 31,	
	2015	2014
	(in thousands)	
Prepaid expenses and other current assets	$ 60,278	$ 50,704
Accrued expenses and other payables	(27,950)	(42,214)
Net commodity derivative asset	$ 32,328	$ 8,490

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The following table summarizes our open commodity derivative contract positions at March 31, 2015 and 2014. We do not account for these derivatives as hedges.

Contracts	Settlement Period		Net Long (Short) Notional Units (Barrels)		Fair Value of Net Assets (Liabilities)
			(in thousands)		
At March 31, 2015					
Cross-commodity (1)	April 2015	March 2016	98	$	(105)
Crude oil fixed-price (2)	April 2015	June 2015	(1,113)		(171)
Crude oil index-price (3)	April 2015	July 2015	751		1,835
Propane fixed-price (4)	April 2015	December 2016	193		(2,842)
Refined products fixed-price (4)	April 2015	December 2015	(3,005)		84,996
Other	April 2015	December 2015			2,296
					86,009
Net cash collateral held					(53,681)
Net commodity derivatives on consolidated balance sheet				$	32,328
At March 31, 2014					
Cross-commodity (1)	April 2014	March 2015	140	$	(1,876)
Crude oil fixed-price (2)	April 2014	March 2015	(1,600)		(2,796)
Crude oil index-price (3)	April 2014	December 2015	3,598		6,099
Propane fixed-price (4)	April 2014	March 2015	60		1,753
Refined products fixed-price (4)	April 2014	July 2014	732		560
Renewables fixed-price (4)	April 2014	July 2014	106		4,084
Other	April 2014				210
					8,034
Net cash collateral provided					456
Net commodity derivatives on consolidated balance sheet				$	8,490

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(1) Cross-commodity We may purchase or sell a physical commodity where the underlying contract pricing mechanisms are tied to different commodity price indices. The contracts listed in this table as Cross-commodity represent derivatives we have entered into as an economic hedge against the risk of one commodity price moving relative to another commodity price.

(2) Crude oil fixed-price Our crude oil logistics segment routinely purchases crude oil inventory to enable us to fulfill future orders expected to be placed by our customers. The contracts listed in this table as Crude oil fixed-price represent derivatives we have entered into as an economic hedge against the risk that crude oil prices will decline while we are holding the inventory.

(3) Crude oil index-price Our crude oil logistics segment may purchase or sell crude oil where the underlying contract pricing mechanisms are tied to different crude oil indices. These indices may vary in the type or location of crude oil, or in the timing of delivery within a given month. The contracts listed in this table as Crude oil index-price represent derivatives we have entered into as an economic hedge against the risk of one crude oil index moving relative to another crude oil index.

(4) Commodity fixed-price We may have fixed price physical obligations, including inventory, offset by floating price physical sales or have floating price physical purchases offset by fixed price physical sales. The contracts listed in the this table as fixed-price represent derivatives we

have entered into as an economic hedge against the risk of mismatches between fixed and floating price physical obligations.

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We recorded the following net gains (losses) from our commodity derivatives to cost of sales (in thousands):

Year Ending March 31,		
2015	$	219,421
2014		(43,655)
2013		(4,376)

Credit Risk

We maintain credit policies with regard to our counterparties on the derivative financial instruments that we believe minimize our overall credit risk, including an evaluation of potential counterparties financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

We may enter into industry standard master netting agreements and may enter into cash collateral agreements requiring the counterparty to deposit funds into a brokerage margin account. The netting agreements reduce our credit risk by providing for net settlement of any offsetting positive and negative exposures with counterparties. The cash collateral agreements reduce the level of our net counterparty credit risk because the amount of collateral represents additional funds that we may access to net settle positions due us, and the amount of collateral adjusts each day in response to changes in the market value of counterparty derivatives.

Our counterparties consist primarily of financial institutions and energy companies. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

Failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded in our consolidated balance sheets and recognized in our net income.

Interest Rate Risk

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, 2015, we had $1.4 billion of outstanding borrowings under our Revolving Credit Facility at a rate of 2.18%. A change in interest rates of 0.125% would result in an increase or decrease of our annual interest expense of $1.7 million, based on borrowings outstanding at March 31, 2015.

The TLP Credit Facility is variable-rate debt with interest rates that are generally indexed to bank prime or LIBOR interest rates. At March 31, 2015, TLP had $250.0 million of outstanding borrowings under the TLP Credit Facility at a rate of 2.67%. A change in interest rates of 0.125%

would result in an increase or decrease in TLP s annual interest expense of $0.3 million, based on borrowings outstanding at March 31, 2015.

Fair Value of Fixed-Rate Notes

The following table provides estimates of the fair values of our fixed-rate notes at March 31, 2015 (in thousands):

5.125% Notes due 2019	$	396,000
6.875% Notes due 2021		472,500
6.650% Notes due 2022		253,475

For the 2019 Notes and the 2021 Notes, the fair value estimates were developed based on publicly traded quotes. These fair value estimates would be classified as Level 1 in the fair value hierarchy.

For the 2022 Notes, the fair value estimate was developed using observed yields on publicly traded notes issued by other entities, adjusted for differences in the key terms of those notes and the key terms of our notes (examples include differences in the tenor of the debt, credit standing of the issuer, whether the notes are publicly traded, and whether the notes are secured or unsecured). This fair value estimate would be classified as Level 3 in the fair value hierarchy.

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Note 13 Segments

Certain financial data related to our segments is shown below. Transactions between segments are recorded based on prices negotiated between the segments.

Our liquids and retail propane segments each consist of two divisions, which are organized based on the location of the operations. Our refined products and renewables segment began with our December 2013 acquisition of Gavilon Energy and expanded with our July 2014 acquisition of TransMontaigne.

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Items labeled corporate and other in the table below include the operations of a compressor leasing business that we sold in February 2014 and certain natural gas marketing operations that we acquired in our December 2013 acquisition of Gavilon Energy and wound down during fiscal year 2014. The corporate and other category also includes certain corporate expenses that are incurred and are not allocated to the reportable segments. This data is included to reconcile the data for the reportable segments to data in our consolidated financial statements.

	Year Ended March 31, 2015	Year Ended March 31, 2014 (in thousands)	Year Ended March 31, 2013
Revenues:			
Crude oil logistics			
Crude oil sales	$ 6,609,685	$ 4,559,923	$ 2,322,706
Crude oil transportation and other	55,535	36,469	16,442
Water solutions			
Service fees	105,682	58,161	34,792
Recovered hydrocarbons	81,762	67,627	19,542
Water transportation	10,760	17,312	7,893
Other revenues	1,838		
Liquids			
Propane sales	1,263,113	1,632,948	841,448
Other product sales	1,111,434	1,231,965	858,276
Other revenues	31,294	31,062	33,954
Retail propane			
Propane sales	347,575	388,225	288,410
Distillate sales	106,037	127,672	106,192
Other revenues	35,585	35,918	35,856
Refined products and renewables			
Refined products sales	6,684,045	1,180,895	
Renewables sales	473,885	176,781	
Service fees	74,842		
Corporate and other	1,916	437,713	4,233
Elimination of intersegment sales	(192,931)	(283,397)	(151,977)
Total revenues	$ 16,802,057	$ 9,699,274	$ 4,417,767
Depreciation and Amortization:			
Crude oil logistics	$ 38,626	$ 22,111	$ 9,176
Water solutions	73,618	55,105	20,923
Liquids	13,513	11,018	11,085
Retail propane	31,827	28,878	25,496
Refined products and renewables	32,948	625	
Corporate and other	3,417	3,017	2,173
Total depreciation and amortization	$ 193,949	$ 120,754	$ 68,853
Operating Income (Loss):			
Crude oil logistics	$ (35,832)	$ 678	$ 34,236
Water solutions	45,031	10,317	8,576
Liquids	45,072	71,888	30,336
Retail propane	64,075	61,285	46,869
Refined products and renewables	54,567	6,514	
Corporate and other	(85,802)	(44,117)	(32,710)
Total operating income	$ 87,111	$ 106,565	$ 87,307

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The following table summarizes additions to property, plant and equipment for each segment. This information has been prepared on the accrual basis, and includes property, plant and equipment acquired in acquisitions.

	Year Ended March 31, 2015	2014 (in thousands)	2013
Additions to property, plant and equipment:			
Crude oil logistics	$ 58,747	$ 204,642	$ 89,860
Water solutions	186,007	100,877	137,116
Liquids	114,180	52,560	15,129
Retail propane	35,602	24,430	66,933
Refined products and renewables	573,954	1,238	
Corporate and other	1,286	7,242	17,858
Total	$ 969,776	$ 390,989	$ 326,896

The following tables summarize long-lived assets (consisting of net property, plant and equipment, net intangible assets, and goodwill) and total assets by segment:

	March 31, 2015 (in thousands)	2014
Total assets:		
Crude oil logistics	$ 2,337,188	$ 1,710,776
Water solutions	1,185,929	876,305
Liquids	713,547	556,152
Retail propane	542,476	541,832
Refined products and renewables	1,668,836	317,726
Corporate and other	99,525	144,840
Total	$ 6,547,501	$ 4,147,631
Long-lived assets, net:		
Crude oil logistics	$ 1,327,538	$ 970,986
Water solutions	1,119,794	849,070
Liquids	534,560	275,836
Retail propane	467,652	438,324
Refined products and renewables	808,757	75,170
Corporate and other	50,192	47,961
Total	$ 4,308,493	$ 2,657,347

Note 14 Disposals and Impairments

During the year ended March 31, 2015, we sold a natural gas liquids terminal and recorded a loss in our consolidated statement of operations of $29.9 million, which included a loss on property, plant and equipment of $21.7 million and a loss of $8.2 million on goodwill allocated to the assets sold. This loss is reported within loss on disposal or impairment of assets, net in our consolidated statement of operations.

During the year ended March 31, 2015, we sold the water transportation business of our water solutions segment and recorded a loss in our consolidated statement of operations of $4.0 million, which included a loss on property, plant and equipment of $2.2 million and a loss of $1.8 million on goodwill allocated to the assets sold. This loss is reported within loss on disposal or impairment of assets, net in our consolidated statement of operations.

During the year ended March 31, 2015, we recorded a loss on abandonment of $3.1 million related to the property, plant and equipment of water disposal facilities that we have retired. This loss is reported within loss on disposal or impairment of assets, net in our consolidated statement of operations.

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We acquired Gavilon Energy in December 2013, which operated a natural gas marketing business. During March 2014, we assigned all of the storage and transportation contracts of the natural gas marketing business to a third party. Since these contracts were at unfavorable terms relative to current market conditions, we paid $44.8 million to assign these contracts. We recorded a liability of $50.8 million related to these storage and transportation contracts in the acquisition accounting, and we amortized $6.0 million of this balance as a reduction to cost of sales during the period from the acquisition date through the date we assigned the contracts. We also assigned all forward purchase and sale contracts and all financial derivative contracts, and thereby wound down the natural gas business. Our consolidated statement of operations for the year ended March 31, 2014 includes $1.4 million of operating income related to the natural gas business, which is reported within corporate and other in the segment disclosures in Note 13.

We acquired High Sierra in June 2012, which operated a compressor leasing business. We sold the compressor leasing business in February 2014 for $10.8 million (net of the amount due to the owner of the noncontrolling interest in the business). We recorded a gain on the sale of the business of $4.4 million, $1.6 million of which was attributable to the disposal of the noncontrolling interest. We reported the gain as a reduction to loss on disposal or impairment of assets, net in our consolidated statement of operations. Our consolidated statement of operations for the year ended March 31, 2014 includes $2.3 million of operating income related to the compressor leasing business, which is reported within corporate and other in the segment disclosures in Note 13.

During the year ended March 31, 2014, we recorded an impairment of $5.3 million to the property, plant and equipment of one of our natural gas liquids terminals in our liquids segment, which is reported within loss on disposal or impairment of assets, net in our consolidated statement of operations.

During the year ended March 31, 2014, two of our water solutions facilities in our water solutions segment experienced damage to their property, plant and equipment as a result of lightning strikes. We recorded a write-down to property, plant and equipment of $1.5 million related to these incidents, which is reported within loss on disposal or impairment of assets, net in our consolidated statement of operations.

Note 15 Transactions with Affiliates

SemGroup Corporation (SemGroup) holds ownership interests in our general partner. We sell product to and purchase product from SemGroup, and these transactions are included within revenues and cost of sales in our consolidated statements of operations. We also lease crude oil storage from SemGroup.

We purchase ethanol from one of our equity method investees. These transactions are reported within cost of sales in our consolidated statements of operations.

Certain members of our management own interests in entities which we have purchased products and services and to which we have sold products and services. The majority of our transactions with such entities represented crude oil purchases and sales and are reported within revenues or cost of sales in our consolidated statements of operations, although $27.5 million of these transactions during the year ended March 31, 2015 represented capital expenditures and were recorded as increases to property, plant and equipment.

The above transactions are summarized in the following table:

	Year Ended March 31, 2015	2014 (in thousands)	2013
Sales to SemGroup	$ 88,276	$ 160,993	$ 54,726
Purchases from SemGroup	130,134	300,164	102,351
Sales to equity method investees	14,493		
Purchases from equity method investees	149,828	47,731	
Sales to entities affiliated with management	2,151	110,824	16,828
Purchases from entities affiliated with management	29,419	120,038	60,942

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Receivables from affiliates consist of the following:

	March 31, 2015	March 31, 2014
	(in thousands)	
Receivables from SemGroup	$ 13,443	$ 7,303
Receivables from equity method investees	652	
Receivables from entities affiliated with management	3,103	142
Total	$ 17,198	$ 7,445

Payables to affiliates consist of the following:

	March 31, 2015	March 31, 2014
	(in thousands)	
Payables to SemGroup	$ 11,546	$ 27,738
Payables to equity method investees	6,788	48,454
Payables to entities affiliated with management	7,460	654
Total	$ 25,794	$ 76,846

We also have a loan receivable of $8.2 million at March 31, 2015 from one of our equity method investees. A portion of the loan matures August 29, 2018 and the remaining portion matures August 29, 2019.

We completed a merger with High Sierra in June 2012. We paid $91.8 million of cash, net of $5.0 million of cash acquired, and issued 18,018,468 common units to acquire High Sierra Energy, LP. We also paid $97.4 million of High Sierra Energy, LP s long-term debt and other obligations. Our general partner acquired High Sierra Energy GP, LLC by paying $50.0 million of cash and issuing equity. Our general partner then contributed its ownership interests in High Sierra Energy GP, LLC to us, in return for which we paid our general partner $50.0 million of cash and issued 2,685,042 common units to our general partner.

During the year ended March 31, 2014, we completed the acquisition of a crude oil logistics business owned by an employee. We paid $11.0 million of cash for this acquisition. During the year ended March 31, 2013, we completed two business combinations with entities in which members of our management owned interests. We paid $14.0 million of cash (net of cash acquired) on a combined basis for these two acquisitions. We also paid $5.0 million under a non-compete agreement to an employee.

Note 16 Other Matters

Purchase of Pipeline Capacity Allocations

On certain interstate refined product pipelines, shipment demand exceeds available capacity, and capacity is allocated to shippers based on their historical shipment volumes. During the year ended March 31, 2015, we paid $24.2 million to acquire certain refined product pipeline capacity allocations from other shippers.

Crude Oil Rail Transloading Facility

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 which the producers paid us a specified amount in March 2015 and committed to pay us specified additional amounts over a period of 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 in our consolidated statement of operations, net of certain project abandonment costs.

Prior to terminating these contracts, we leased certain railcars that we expected to utilize to service the contracts with the producers. We will attempt to sublease these railcars or utilize them in our other operations, but we are unable to predict to what extent we will be able to utilize these railcars.

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Grand Mesa Pipeline, LLC

In September 2014, we entered into a joint venture with RimRock Midstream, LLC (RimRock), whereby each party owned a 50% interest in Grand Mesa. Grand Mesa is constructing a crude oil pipeline originating in Weld County, Colorado and terminating at our Cushing, Oklahoma terminal. In October 2014, Grand Mesa completed a successful open season in which it received the requisite support, in the form of ship-or-pay volume commitments from multiple shippers, to begin construction of a 20-inch pipeline system. In November 2014, we acquired RimRock s 50% ownership interest in Grand Mesa for $310.0 million in cash and allocated the purchase price to a customer commitment intangible asset. We anticipate that the pipeline will commence service in the second half of calendar year 2016, at which time we will begin to amortize this intangible asset.

Note 17 Quarterly Financial Data (Unaudited)

Our summarized unaudited quarterly financial data is presented below. The computation of net income per common unit is done separately by quarter and year. The total of net income per common unit of the individual quarters may not equal the net income per common unit for the year, due primarily to the income allocation between the general partner and limited partners and variations in the weighted-average units outstanding used in computing such amounts.

Our retail propane segment s business is seasonal due to weather conditions in our service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Our liquids segment is also subject to seasonal fluctuations, as demand for propane and butane is typically higher during the winter months. Our operating revenues from our other segments are less weather sensitive. Additionally, the acquisitions described in Note 4 impact the comparability of the quarterly information within the year, and year to year.

	Quarter Ended				Year Ended
	June 30, 2014	**September 30, 2014**	**December 31, 2014**	**March 31, 2015**	**March 31, 2015**
	(in thousands, except unit and per unit data)				
Total revenues	$ 3,648,614	$ 5,380,526	$ 4,552,146	$ 3,220,771	$ 16,802,057
Total cost of sales	$ 3,534,053	$ 5,179,465	$ 4,311,668	$ 2,933,021	$ 15,958,207
Net income (loss) (1)	$ (39,910)	$ (15,879)	$ (5,269)	$ 90,942	$ 29,884
Net income (loss) attributable to parent equity (1)	$ (39,975)	$ (19,224)	$ (10,918)	$ 86,778	$ 16,661
Income (loss) per common unit, basic and diluted (1)	$ (0.61)	$ (0.34)	$ (0.26)	$ 0.78	$ (0.29)
Weighted average common units outstanding basic and diluted	74,126,205	88,331,653	88,545,764	94,447,339	86,359,300

	Quarter Ended				Year Ended
	June 30, 2013	**September 30, 2013**	**December 31, 2013**	**March 31, 2014**	**March 31, 2014**
	(in thousands, except unit and per unit data)				
Total revenues	$ 1,385,957	$ 1,593,937	$ 2,743,445	$ 3,975,935	$ 9,699,274
Total cost of sales	$ 1,303,076	$ 1,488,850	$ 2,576,029	$ 3,764,744	$ 9,132,699

Net income (loss)	$	(17,508)	$	(932)	$	24,052	$	43,146	$	48,758
Net income (loss) attributable to parent equity	$	(17,633)	$	(941)	$	23,898	$	42,331	$	47,655
Income (loss) per common unit, basic and diluted	$	(0.35)	$	(0.05)	$	0.27	$	0.46	$	0.51
Weighted average common units outstanding basic and diluted		47,703,313		58,909,389		67,941,726		73,421,309		61,970,471

(1) As described in Note 16, in March 2015, we agreed to release certain producers from certain commitments in return for which the producers paid us a specified amount in March 2015 and committed to pay us specified additional amounts over a period of 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.

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Note 18 Subsequent Events

Water Solutions Facility Acquisitions

As described in Note 4, we are party to a development agreement that provides us a right to purchase water treatment and disposal facilities developed by the other party to the agreement. During April and May 2015, we purchased three water treatment and disposal facilities under this development agreement. On a combined basis, the purchase price for these facilities was $39.0 million of cash.

Note 19 Consolidating Guarantor and Non-Guarantor Financial Information

Certain of our wholly owned subsidiaries have, jointly and severally, fully and unconditionally guaranteed the 2019 Notes and the 2021 Notes (described in Note 8). Pursuant to Rule 3-10 of Regulation S-X, we have presented in columnar format the consolidating financial information for NGL Energy Partners LP, NGL Energy Finance Corp. (which, along with NGL Energy Partners LP, is a co-issuer of the 2019 Notes and 2021 Notes), the guarantor subsidiaries on a combined basis, and the non-guarantor subsidiaries on a combined basis in the tables below.

During the periods presented in the tables below, the status of certain subsidiaries changed, in that they either became guarantors of or ceased to be guarantors of the 2019 Notes and 2021 Notes. Such changes have been given retrospective application in the tables below.

There are no significant restrictions upon the ability of the parent or any of the guarantor subsidiaries to obtain funds from their respective subsidiaries by dividend or loan, other than restrictions contained in TLP s Credit Facility. None of the assets of the guarantor subsidiaries (other than the investments in non-guarantor subsidiaries) represent restricted net assets pursuant to Rule 4-08(e)(3) of Regulation S-X under the Securities Act of 1933, as amended.

For purposes of the tables below, (i) the consolidating financial information is presented on a legal entity basis, (ii) investments in consolidated subsidiaries are accounted for as equity method investments, and (iii) contributions, distributions, and advances to or from consolidated entities are reported on a net basis within net changes in advances with consolidated entities in the consolidating cash flow tables below.

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NGL ENERGY PARTNERS LP

Consolidating Balance Sheet

(U.S. Dollars in Thousands)

	March 31, 2015					
	NGL Energy Partners LP (Parent) (1)	NGL Energy Finance Corp. (1)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 29,115	$	$ 9,757	$ 2,431	$	$ 41,303
Accounts receivable trade, net of allowance for doubtful accounts			1,007,001	17,225		1,024,226
Accounts receivable affiliates	5		16,610	583		17,198
Inventories			440,026	1,736		441,762
Prepaid expenses and other current assets			104,528	16,327		120,855
Total current assets	29,120		1,577,922	38,302		1,645,344
PROPERTY, PLANT AND EQUIPMENT, net of accumulated depreciation			1,093,018	524,371		1,617,389
GOODWILL			1,372,690	30,071		1,402,761
INTANGIBLE ASSETS, net of accumulated amortization	17,834		1,195,896	74,613		1,288,343
INVESTMENTS IN UNCONSOLIDATED ENTITIES			217,600	255,073		472,673
NET INTERCOMPANY RECEIVABLES (PAYABLES)	1,363,792		(1,319,724)	(44,068)		
INVESTMENTS IN CONSOLIDATED SUBSIDIARIES	1,834,738		56,690		(1,891,428)	
LOAN RECEIVABLE AFFILIATES			8,154			8,154
OTHER NONCURRENT ASSETS			110,120	2,717		112,837
Total assets	$ 3,245,484	$	$ 4,312,366	$ 881,079	$ (1,891,428)	$ 6,547,501
LIABILITIES AND EQUITY						
CURRENT LIABILITIES:						
Accounts payable trade	$	$	$ 820,441	$ 12,939	$	$ 833,380
Accounts payable affiliates			25,690	104		25,794
Accrued expenses and other payables	19,690		165,819	9,607		195,116
Advance payments received from customers			53,903	331		54,234
Current maturities of long-term debt			4,413	59		4,472
Total current liabilities	19,690		1,070,266	23,040		1,112,996

LONG-TERM DEBT, net of current maturities	1,100,000		1,395,100	250,199		2,745,299
OTHER NONCURRENT LIABILITIES			12,262	3,824		16,086
EQUITY						
Partners equity	2,125,794		1,834,738	604,125	(2,438,754)	2,125,903
Accumulated other comprehensive loss				(109)		(109)
Noncontrolling interests					547,326	547,326
Total equity	2,125,794		1,834,738	604,016	(1,891,428)	2,673,120
Total liabilities and equity	$ 3,245,484	$	$ 4,312,366	$ 881,079	$ (1,891,428)	$ 6,547,501

(1) The parent and NGL Energy Finance Corp. are co-issuers of the 2019 Notes and 2021 Notes. Since the parent received the proceeds from the issuance of the 2019 Notes and 2021 Notes, all activity has been reflected in the parent column.

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NGL ENERGY PARTNERS LP

Consolidating Balance Sheet

(U.S. Dollars in Thousands)

	March 31, 2014					
	NGL Energy Partners LP (Parent) (1)	NGL Energy Finance Corp. (1)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 1,181	$	$ 8,728	$ 531	$	$ 10,440
Accounts receivable trade, net of allowance for doubtful accounts			864,789	13,115		877,904
Accounts receivable affiliates			7,445			7,445
Inventories			306,434	3,726		310,160
Prepaid expenses and other current assets			80,294	56		80,350
Total current assets	1,181		1,267,690	17,428		1,286,299
PROPERTY, PLANT AND EQUIPMENT, net of accumulated depreciation			770,516	65,332		835,848
GOODWILL			1,083,395	1,998		1,085,393
INTANGIBLE ASSETS, net of accumulated amortization	12,721		721,753	1,632		736,106
INVESTMENTS IN UNCONSOLIDATED ENTITIES			194,821			194,821
NET INTERCOMPANY RECEIVABLES (PAYABLES)	764,995		(720,737)	(44,258)		
INVESTMENTS IN CONSOLIDATED SUBSIDIARIES	1,462,502		17,673		(1,480,175)	
OTHER NONCURRENT ASSETS			9,043	121		9,164
Total assets	$ 2,241,399	$	$ 3,344,154	$ 42,253	$ (1,480,175)	$ 4,147,631
LIABILITIES AND EQUITY						
CURRENT LIABILITIES:						
Accounts payable trade	$	$	$ 705,344	$ 13,959	$	$ 719,303
Accounts payable affiliates			73,703	3,143		76,846
Accrued expenses and other payables	14,820		124,923	1,947		141,690
Advance payments received from customers			29,891	74		29,965
Current maturities of long-term debt			7,058	22		7,080
Total current liabilities	14,820		940,919	19,145		974,884

LONG-TERM DEBT, net of current maturities	700,000		929,754	80		1,629,834
OTHER NONCURRENT LIABILITIES			10,979	81		11,060
EQUITY						
Partners equity	1,526,579		1,462,691	22,994	(1,485,449)	1,526,815
Accumulated other comprehensive loss			(189)	(47)		(236)
Noncontrolling interests					5,274	5,274
Total equity	1,526,579		1,462,502	22,947	(1,480,175)	1,531,853
Total liabilities and equity	$ 2,241,399	$	$ 3,344,154	$ 42,253	$ (1,480,175)	$ 4,147,631

(1) The parent and NGL Energy Finance Corp. are co-issuers of the 2021 Notes. Since the parent received the proceeds from the issuance of the 2021 Notes, all activity has been reflected in the parent column.

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NGL ENERGY PARTNERS LP

Consolidating Statement of Operations

(U.S. Dollars in Thousands)

	Year Ended March 31, 2015					
	NGL Energy Partners LP (Parent) (1)	NGL Energy Finance Corp. (1)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
REVENUES	$	$	$ 16,648,382	$ 189,979	$ (36,304)	$ 16,802,057
COST OF SALES			15,934,529	59,825	(36,147)	15,958,207
OPERATING COSTS AND EXPENSES:						
Operating			314,621	57,555		372,176
Loss on disposal or impairment of assets, net			11,619	29,565		41,184
General and administrative			131,898	17,532		149,430
Depreciation and amortization			161,906	32,043		193,949
Operating Income (Loss)			93,809	(6,541)	(157)	87,111
OTHER INCOME (EXPENSE):						
Earnings of unconsolidated entities			6,640	5,463		12,103
Interest expense	(65,723)		(39,023)	(5,423)	46	(110,123)
Other income, net			36,953	264	(46)	37,171
Income (Loss) Before Income Taxes	(65,723)		98,379	(6,237)	(157)	26,262
INCOME TAX (PROVISION) BENEFIT			3,795	(173)		3,622
EQUITY IN NET INCOME (LOSS) OF CONSOLIDATED SUBSIDIARIES	82,384		(19,633)		(62,751)	
Net Income (Loss)	16,661		82,541	(6,410)	(62,908)	29,884
LESS: NET INCOME ALLOCATED TO GENERAL PARTNER					(45,679)	(45,679)
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS					(13,223)	(13,223)

NET INCOME (LOSS) ALLOCATED TO LIMITED PARTNERS	$	16,661	$		$	82,541	$	(6,410)	$	(121,810)	$	(29,018)

(1) The parent and NGL Energy Finance Corp. are co-issuers of the 2019 Notes and 2021 Notes.

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NGL ENERGY PARTNERS LP

Consolidating Statement of Operations

(U.S. Dollars in Thousands)

	Year Ended March 31, 2014					
	NGL Energy Partners LP (Parent) (1)	NGL Energy Finance Corp. (1)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
REVENUES	$	$	$ 9,560,124	$ 139,519	$ (369)	$ 9,699,274
COST OF SALES			9,011,011	122,057	(369)	9,132,699
OPERATING COSTS AND EXPENSES:						
Operating			250,841	8,958		259,799
Loss (gain) on disposal or impairment of assets, net			6,373	(2,776)		3,597
General and administrative			73,756	2,104		75,860
Depreciation and amortization			117,573	3,181		120,754
Operating Income			100,570	5,995		106,565
OTHER INCOME (EXPENSE):						
Earnings of unconsolidated entities			1,898			1,898
Interest expense	(31,818)		(27,031)	(51)	46	(58,854)
Other income (expense), net			202	(70)	(46)	86
Income (Loss) Before Income Taxes	(31,818)		75,639	5,874		49,695
INCOME TAX PROVISION			(937)			(937)
EQUITY IN NET INCOME OF CONSOLIDATED SUBSIDIARIES	79,473		4,771		(84,244)	
Net Income	47,655		79,473	5,874	(84,244)	48,758
LESS: NET INCOME ALLOCATED TO GENERAL PARTNER					(14,148)	(14,148)
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS					(1,103)	(1,103)
NET INCOME ALLOCATED TO LIMITED PARTNERS	$ 47,655	$	$ 79,473	$ 5,874	$ (99,495)	$ 33,507

(1) The parent and NGL Energy Finance Corp. are co-issuers of the 2021 Notes.

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NGL ENERGY PARTNERS LP

Consolidating Statement of Operations

(U.S. Dollars in Thousands)

	Year Ended March 31, 2013				
	NGL Energy Partners LP (Parent)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
REVENUES	$	$ 4,409,198	$ 8,878	$ (309)	$ 4,417,767
COST OF SALES		4,038,251	1,168	(309)	4,039,110
OPERATING COSTS AND EXPENSES:					
Operating		164,870	4,742		169,612
Loss on disposal or impairment of assets, net		74	113		187
General and administrative		52,461	237		52,698
Depreciation and amortization		66,916	1,937		68,853
Operating Income		86,626	681		87,307
OTHER INCOME (EXPENSE):					
Interest expense	(13,041)	(19,951)	(48)	46	(32,994)
Loss on early extinguishment of debt		(5,769)			(5,769)
Other income (expense), net		1,666	(99)	(46)	1,521
Income (Loss) Before Income Taxes	(13,041)	62,572	534		50,065
INCOME TAX PROVISION		(1,875)			(1,875)
EQUITY IN NET INCOME OF CONSOLIDATED SUBSIDIARIES	60,981	284		(61,265)	
Net Income	47,940	60,981	534	(61,265)	48,190
LESS: NET INCOME ALLOCATED TO GENERAL PARTNER				(2,917)	(2,917)
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS				(250)	(250)
NET INCOME ALLOCATED TO LIMITED PARTNERS	$ 47,940	$ 60,981	$ 534	$ (64,432)	$ 45,023

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NGL ENERGY PARTNERS LP

Consolidating Statements of Comprehensive Income (Loss)

(U.S. Dollars in Thousands)

	Year Ended March 31, 2015					
	NGL Energy Partners LP (Parent) (1)	NGL Energy Finance Corp. (1)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net income (loss)	$ 16,661	$	$ 82,541	$ (6,410)	$ (62,908)	$ 29,884
Other comprehensive income (loss)			189	(62)		127
Comprehensive income (loss)	$ 16,661	$	$ 82,730	$ (6,472)	$ (62,908)	$ 30,011

(1) The parent and NGL Energy Finance Corp. are co-issuers of the 2019 Notes and 2021 Notes.

	Year Ended March 31, 2014					
	NGL Energy Partners LP (Parent) (2)	NGL Energy Finance Corp. (2)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net income	$ 47,655	$	$ 79,473	$ 5,874	$ (84,244)	$ 48,758
Other comprehensive loss			(189)	(71)		(260)
Comprehensive income	$ 47,655	$	$ 79,284	$ 5,803	$ (84,244)	$ 48,498

(2) The parent and NGL Energy Finance Corp are co-issuers of the 2021 Notes.

	Year Ended March 31, 2013				
	NGL Energy Partners LP (Parent)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net income	$ 47,940	$ 60,981	$ 534	$ (61,265)	$ 48,190
Other comprehensive loss			(7)		(7)
Comprehensive income	$ 47,940	$ 60,981	$ 527	$ (61,265)	$ 48,183

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NGL ENERGY PARTNERS LP

Consolidating Statement of Cash Flows

(U.S. Dollars in Thousands)

	Year Ended March 31, 2015				
	NGL Energy Partners LP (Parent) (1)	NGL Energy Finance Corp. (1)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (59,448)	$	$ 287,956	$ 33,886	$ 262,394
INVESTING ACTIVITIES:					
Purchases of long-lived assets			(198,847)	(4,913)	(203,760)
Purchases of pipeline capacity allocations			(24,218)		(24,218)
Purchase of equity interest in Grand Mesa Pipeline			(310,000)		(310,000)
Acquisitions of businesses, including acquired working capital, net of cash acquired	(124,281)		(831,505)	(5,136)	(960,922)
Cash flows from commodity derivatives			199,165		199,165
Proceeds from sales of assets			11,806	14,456	26,262
Investments in unconsolidated entities			(13,244)	(20,284)	(33,528)
Distributions of capital from unconsolidated entities			5,030	5,793	10,823
Loan for facility under construction			(63,518)		(63,518)
Payments on loan for facility under construction			1,625		1,625
Loans to affiliates			(8,154)		(8,154)
Other			4		4
Net cash used in investing activities	(124,281)		(1,231,856)	(10,084)	(1,366,221)
FINANCING ACTIVITIES:					
Proceeds from borrowings under revolving credit facilities			3,663,000	101,500	3,764,500
Payments on revolving credit facilities			(3,194,500)	(85,500)	(3,280,000)
Issuance of notes	400,000				400,000
Payments on other long-term debt			(6,666)	(22)	(6,688)
Debt issuance costs	(8,150)		(2,926)		(11,076)
Contributions from general partner	823				823
Contributions from noncontrolling interest owners				9,433	9,433
Distributions to partners	(242,595)				(242,595)
Distributions to noncontrolling interest owners				(27,147)	(27,147)
Proceeds from sale of common units, net of offering costs	541,128				541,128
Taxes paid on behalf of equity incentive participants			(13,491)		(13,491)
	(479,543)		499,709	(20,166)	

Net changes in advances with consolidated entities					
Other			(197)		(197)
Net cash provided by financing activities	211,663		944,929	(21,902)	1,134,690
Net increase in cash and cash equivalents	27,934		1,029	1,900	30,863
Cash and cash equivalents, beginning of period	1,181		8,728	531	10,440
Cash and cash equivalents, end of period	$ 29,115	$	$ 9,757	$ 2,431	$ 41,303

(1) The parent and NGL Energy Finance Corp. are co-issuers of the 2019 Notes and 2021 Notes.

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NGL ENERGY PARTNERS LP

Consolidating Statement of Cash Flows

(U.S. Dollars in Thousands)

	Year Ended March 31, 2014				
	NGL Energy Partners LP (Parent) (1)	NGL Energy Finance Corp. (1)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
OPERATING ACTIVITIES:					
Net cash provided by (used in) operating activities	$ (16,625)	$	$ 99,754	$ 2,107	$ 85,236
INVESTING ACTIVITIES:					
Purchases of long-lived assets			(118,455)	(46,693)	(165,148)
Acquisitions of businesses, including acquired working capital, net of cash acquired	(334,154)		(932,373)	(2,283)	(1,268,810)
Cash flows from commodity derivatives			(35,956)		(35,956)
Proceeds from sales of assets			12,884	11,776	24,660
Investments in unconsolidated entities			(11,515)		(11,515)
Distributions of capital from unconsolidated entities			1,591		1,591
Other			540	(735)	(195)
Net cash used in investing activities	(334,154)		(1,083,284)	(37,935)	(1,455,373)
FINANCING ACTIVITIES:					
Proceeds from borrowings under revolving credit facilities			2,545,500		2,545,500
Payments on revolving credit facilities			(2,101,000)		(2,101,000)
Issuance of notes	450,000				450,000
Proceeds from borrowings on other long-term debt			780	100	880
Payments on other long-term debt			(8,802)	(17)	(8,819)
Debt issuance costs	(12,931)		(11,664)		(24,595)
Contributions from general partner	765				765
Contributions from noncontrolling interest owners				2,060	2,060
Distributions to partners	(145,090)				(145,090)
Distributions to noncontrolling interest owners				(840)	(840)
Proceeds from sale of common units, net of offering costs	650,155				650,155
Net changes in advances with consolidated entities	(590,939)		556,238	34,701	
Net cash provided by financing activities	351,960		981,052	36,004	1,369,016
Net increase (decrease) in cash and cash equivalents	1,181		(2,478)	176	(1,121)
Cash and cash equivalents, beginning of period			11,206	355	11,561
	$ 1,181	$	$ 8,728	$ 531	$ 10,440

Cash and cash equivalents, end of period

(1) The parent and NGL Energy Finance Corp. are co-issuers of the 2021 Notes.

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NGL ENERGY PARTNERS LP

Consolidating Statement of Cash Flows

(U.S. Dollars in Thousands)

	Year Ended March 31, 2013			
	NGL Energy Partners LP (Parent)	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidated
OPERATING ACTIVITIES:				
Net cash provided by (used in) operating activities	$ (12,428)	$ 140,794	$ 4,268	$ 132,634
INVESTING ACTIVITIES:				
Purchases of long-lived assets		(59,903)	(12,572)	(72,475)
Acquisitions of businesses, including acquired working capital, net of cash acquired	(452,087)	(38,718)		(490,805)
Cash flows from commodity derivatives		11,579		11,579
Proceeds from sales of assets		5,080		5,080
Net cash used in investing activities	(452,087)	(81,962)	(12,572)	(546,621)
FINANCING ACTIVITIES:				
Proceeds from borrowings under revolving credit facilities		1,227,975		1,227,975
Payments on revolving credit facilities		(964,475)		(964,475)
Issuance of notes	250,000			250,000
Proceeds from borrowings on other long-term debt		634	19	653
Payments on other long-term debt		(4,837)		(4,837)
Debt issuance costs	(777)	(19,412)		(20,189)
Contributions from general partner	510			510
Contributions from noncontrolling interest owners			403	403
Distributions to partners	(71,608)			(71,608)
Distributions to noncontrolling interest owners			(74)	(74)
Proceeds from sale of common units, net of offering costs	(642)			(642)
Net changes in advances with consolidated entities	286,991	(295,105)	8,114	
Net cash provided by (used in) financing activities	464,474	(55,220)	8,462	417,716
Net increase (decrease) in cash and cash equivalents	(41)	3,612	158	3,729
Cash and cash equivalents, beginning of period	41	7,594	197	7,832
Cash and cash equivalents, end of period	$	$ 11,206	$ 355	$ 11,561

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INDEX TO 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)
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)

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Exhibit Number	Description
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)

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Exhibit Number	Description
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
4.10	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)
4.11	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)
4.12	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)
4.13	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)
4.14	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)
4.15	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)
4.16	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)
4.17	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)
4.18*	Amendment No. 8 to Note Purchase Agreement, dated as of May 1, 2015, among the Partnership and the purchasers named therein
4.19	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)
4.20	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)
4.21	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)
4.22	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)

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Exhibit Number	Description
4.23	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)
4.24*	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
4.25*	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
4.26	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)
4.27	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)
4.28	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)
4.29	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)
4.30	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)
4.31	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)
4.32*	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
4.33*	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
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
10.14	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)

Exhibit Number	Description
10.15+	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)
10.16+	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)
10.17+	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)
10.18*+	NGL Performance Unit Program
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, 2015 and 2014, (ii) Consolidated Statements of Operations for the years ended March 31, 2015, 2014, and 2013, (iii) Consolidated Statements of Comprehensive Income for the years ended March 31, 2015, 2014, and 2013, (iv) Consolidated Statements of Changes in Equity for the years ended March 31, 2015, 2014, and 2013 (v) Consolidated Statements of Cash Flows for the years ended March 31, 2015, 2014, and 2013, and (vi) Notes to Consolidated Financial Statements.

\+ Management contracts or compensatory plans or arrangements.