NGL Energy Partners LP
Form 10-K
May 30, 2018
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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, 2018
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________
Commission File Number: 001-35172
NGL Energy Partners LP
(Exact Name of Registrant as Specified in Its Charter)

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

(918) 481-1119
(Registrant's Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes 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 (§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 (§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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth 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
Emerging growth company o	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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, 2017 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 ($11.55 per Common Unit) was $1.0 billion. For purposes of this computation, all executive officers, directors and 10% beneficial 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, 2018, there were 121,568,058 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. Certain words in this Annual Report such as "anticipate," "believe," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "plan," "project," "will," and similar expressions and statements regarding our plans and objectives for future operations, identify forward-looking statements. Although we and our general partner believe such forward-looking statements are reasonable, neither we nor our general partner can assure they will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those expected. Among the key risk factors that may affect our consolidated financial position and results of operations are:

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

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- 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 complete accretive acquisitions, and integrate acquired assets and businesses;
- changes in the volume of hydrocarbons recovered during the wastewater treatment process;
- changes in the financial condition and results of operations of entities in which we own noncontrolling equity interests;
- changes in applicable laws and regulations, including tax, environmental, transportation, and employment regulations, or new interpretations by regulatory agencies concerning such laws and regulations and the effect of such laws and regulations (now existing or in the future) on our business operations;
- the costs and effects of legal and administrative proceedings;
- any reduction or the elimination of the federal Renewable Fuel Standard;
- changes in the jurisdictional characteristics of, or the applicable regulatory policies with respect to, our pipeline assets; and
- other risks and uncertainties, including those discussed under Part I, Item 1A–"Risk Factors."

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 may be 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 discussed under Part I, Item 1A–"Risk Factors."

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PART I

References in this Annual Report to (i) "NGL Energy Partners LP," the "Partnership," "we," "our," "us," or similar terms refer NGL Energy Partners LP and its operating subsidiaries, (ii) "NGL Energy Holdings LLC" or "general partner" refers to NGL Energy Holdings LLC, our general partner, (iii) "NGL Energy Operating LLC" 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 43 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, 2018. Unless otherwise indicated, this data is as of March 31, 2018.

Item 1. Business

Overview

We are a Delaware limited partnership formed in September 2010. Subsequent to our initial public offering ("IPO") in May 2011, we significantly expanded our operations through numerous acquisitions. At March 31, 2018, our operations include:

- Our Crude Oil Logistics segment purchases crude oil from producers and transports it to refineries or for resale at pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs, and provides storage, terminaling, trucking, marine and pipeline transportation services through its owned assets.
- Our Water Solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms, drilling fluids and drilling muds and performs truck and frac tank washouts. In addition, our Water Solutions segment sells the recovered hydrocarbons that result from performing these services.
- Our Liquids segment supplies natural gas liquids to retailers, wholesalers, refiners, and petrochemical plants throughout the United States and in Canada using its leased underground storage and fleet of leased railcars, markets regionally through its 21 owned terminals throughout the United States, and provides terminaling and storage services at its salt dome storage facility joint venture in Utah.
- Our Retail Propane segment sells propane, distillates, equipment and supplies to end users consisting of residential, agricultural, commercial, and industrial customers and to certain resellers in 21 states and the District of Columbia.
- Our Refined Products and Renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations, purchases refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedules them for delivery at various locations throughout the country. In addition, in certain storage locations, our Refined Products and Renewables segment may also purchase unfinished gasoline blending components for subsequent blending into finished gasoline to supply our marketing business as well as third parties.

For more information regarding our reportable segments, see Note 12 to our consolidated financial statements included in this Annual Report.

Acquisitions

Subsequent to our IPO in May 2011, we significantly expanded our operations through numerous acquisitions. The following summarizes our acquisitions over the past five fiscal years.

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.

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- 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 required us to purchase water solutions facilities developed by the other party to the agreement. During March 2014, we purchased one additional facility under this development agreement. This development agreement was terminated in June 2016.
- 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 included 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 included 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 (see "Dispositions" below for a discussion of the sale of our 50% interest in Glass Mountain), and an interest in E Energy Adams, LLC, an ethanol production facility in the Midwest (see "Dispositions" below for a discussion of the sale of our 20% interest in E Energy Adams, LLC). The operations of Gavilon Energy included the marketing of crude oil, refined products, ethanol, biodiesel, and natural gas liquids, and also included crude oil storage in Cushing, Oklahoma.

Year Ended March 31, 2015

- In July 2014, we acquired TransMontaigne Inc. ("TransMontaigne"). The operations of TransMontaigne included the marketing of refined products. As part of this transaction, we also purchased inventory from the previous owner of TransMontaigne, the 2% general partner interest, the incentive distribution rights, a 19.7% limited partner interest in TransMontaigne Partners L.P. ("TLP"), and assumed certain terminaling service agreements with TLP from an affiliate of the previous owner of TransMontaigne. See "Dispositions" below for a discussion of the sale of the general and limited partner interests in TLP.
- In November 2014, we acquired two saltwater disposal facilities in the Bakken shale play in North Dakota.
- In February 2015, we acquired Sawtooth, which owns a natural gas liquids salt dome storage facility in Utah with rail and truck access to western United States markets and entered into a construction agreement to expand the storage capacity of the facility. See "Dispositions" below for a discussion of the joint venture of our Sawtooth business.
- During the year ended March 31, 2015, we acquired 16 water treatment and disposal facilities under the development agreement discussed above.
- During the year ended March 31, 2015, we acquired eight retail propane businesses.

Year Ended March 31, 2016

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

Year Ended March 31, 2017

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In June 2016, we acquired an additional 24.5% interest in NGL Water Pipelines, LLC operating in the Delaware Basin portion of the Permian Basin in West Texas.

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- In June 2016, we acquired the remaining 65% ownership interest in Grassland Water Solutions, LLC (“Grassland”), which we subsequently sold in November 2016 (see “Dispositions” below for a discussion of the sale).
- In September 2016, we acquired the remaining 25% ownership interest in three water solutions facilities in the Eagle Ford shale play in Texas.
- In January 2017, we acquired a natural gas liquids terminal that supports refined products blending in Port Hudson, Louisiana, and a natural gas liquids and condensate facility in Kingfisher, Oklahoma.
- During the year ended March 31, 2017, we acquired three water solutions facilities.
- During the year ended March 31, 2017, we acquired four retail propane businesses.

Year Ended March 31, 2018

- During the year ended March 31, 2018, we acquired the remaining 50% ownership interest in NGL Solids Solutions, LLC.
- During the year ended March 31, 2018, we acquired seven retail propane businesses and certain assets from an equity method investee.

Year Ending March 31, 2019

- On April 24, 2018, we acquired the remaining 18.375% interest in NGL Water Pipelines, LLC operating in the Delaware Basin portion of the Permian Basin in West Texas.
- Subsequent to March 31, 2018, we acquired one saltwater disposal facility and four freshwater facilities.
- Subsequent to March 31, 2018, we acquired three retail propane businesses.

See Note 17 to our consolidated financial statements included in this Annual Report for a further discussion of the acquisitions that occurred subsequent to March 31, 2018.

Dispositions

Sale of General Partner Interest in TLP

On February 1, 2016, we sold our general partner interest in TLP to ArcLight for net proceeds of $343.1 million. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting. As discussed further below, TLP is no longer an equity method investment. As part of this transaction, we retained TransMontaigne Product Services LLC, including its marketing business, customer contracts and its line space on the Colonial and Plantation pipelines, which is a significant part of our Refined Products and Renewables segment. We also entered into lease agreements whereby we will remain the long-term exclusive tenant in the TLP Southeast terminal system. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of TLP Common Units

On April 1, 2016, we sold all of the TLP common units we owned to an affiliate of ArcLight Capital Partners (“ArcLight”) for approximately $112.4 million in cash. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of Grassland

On November 29, 2016, we sold Grassland and received proceeds of $22.0 million. See Note 13 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of Interest in Glass Mountain

On December 22, 2017, we sold our previously held 50% interest in Glass Mountain for net proceeds of $292.1 million. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

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As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Crude Oil Logistics segment have not been classified as discontinued operations.

Sawtooth Joint Venture

On March 30, 2018, we completed the transaction to form a joint venture with Magnum Liquids, LLC, a portfolio company of Haddington Ventures LLC, along with Magnum Development, LLC and other Haddington-sponsored investment entities (collectively “Magnum”) to focus on the storage of natural gas liquids and refined products by combining our Sawtooth salt dome storage facility with Magnum’s refined products rights and adjacent leasehold. Magnum acquired an approximately 28.5% interest in Sawtooth from us, in exchange for consideration consisting of a cash payment of approximately $37.6 million (excluding working capital) and the contribution of certain refined products rights and adjacent leasehold. The disposition of this interest was accounted for as an equity transaction, no gain or loss was recorded and the carrying value of the noncontrolling interest was adjusted to reflect the change in ownership interest of the subsidiary. We own approximately 71.5% of the joint venture; and within the next three years, Magnum has options to acquire our remaining interest for an additional $182.4 million. See Note 15 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of a Portion of Retail Propane Business

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC LPG for net proceeds of $212.4 million in cash at closing. The Retail Propane businesses subject to this transaction consisted of our operations across the Mid-Continent and Western portions of the United States, including three of the seven retail propane businesses we acquired during the year ended March 31, 2018. We retained our Retail Propane businesses located in the Eastern, mid-Atlantic and Southeastern sections of the United States. See Note 15 to our consolidated financial statements included in this Annual Report for a further discussion.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Retail Propane segment have not been classified as discontinued operations.

Sale of Interest in E Energy Adams, LLC

On May 3, 2018, we sold our previously held 20% interest in E Energy Adams, LLC for net proceeds of $18.6 million. See Note 17 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of Retail Propane Business

On May 30, 2018, we entered into a definitive agreement with Superior Plus Corp. to sell our Retail Propane business for $900 million in cash. See Note 17 to our consolidated financial statements included in this Annual Report for a further discussion.

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Primary Service Areas

The following map shows the primary service areas of our businesses at March 31, 2018:

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Organizational Chart

The following chart provides a summarized view of our legal entity structure at March 31, 2018:

(1) Includes (i) NGL Crude Logistics, LLC, which includes the operations of our Crude Oil Logistics business and a portion of our Refined Products and Renewables businesses, (ii) NGL Water Solutions, LLC, which includes the operations of our Water Solutions business, (iii) NGL Liquids, LLC, which includes the operations of our Liquids business, (iv) NGL Propane, LLC, which includes the operations of our Retail Propane business, and (v) TransMontaigne, LLC, which includes the remaining portion of our Refined Products and Renewables businesses.

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Our Business Strategies

Our principle business objectives are to maximize the profitability and stability of our businesses, grow our businesses in an accretive and prudent manner, and maintain a strong balance sheet, all of which we believe will lead to increasing cash flow available for distributions to our unitholders. We intend to accomplish these objectives by executing the following strategies:

- Focus on building a vertically integrated midstream master limited partnership providing multiple services to customers. We continue to enhance our ability to transport crude oil from the wellhead to refiners, refined products from refiners to customers, wastewater from the wellhead to treatment for disposal, recycle, or discharge, and natural gas liquids from processing plants to end users, including retail propane customers.
- Achieve organic growth by investing in new assets that increase volumes, enhance our operations, and generate attractive rates of return. We believe that there are accretive organic growth opportunities that originate from assets we own and operate. We have invested and expect to continue to invest within our existing businesses, particularly within our Crude Oil Logistics and Water Solutions businesses as we grow these businesses with highly accretive, fee-based organic growth opportunities.
- Deliver accretive growth through strategic acquisitions that complement our existing business model and expand our operations. We intend to continue to pursue acquisitions that build upon our vertically integrated business model, add scale to our current operating platforms, and enhance our geographic diversity in our businesses. We have established a successful track record of acquiring companies and assets at attractive prices and we continue to evaluate acquisition opportunities in order to capitalize on this strategy in the future.
- Focus on consistent annual cash flows by adding operations that minimize commodity price risk and generate fee-based, cost-plus, or margin-based revenues under multi-year contracts. We intend to focus on long-term fee-based contracts in addition to back-to-back contracts which minimize commodity price exposure. We continue to increase cash flows that are supported by certain fee-based, multi-year contracts, some of which include acreage dedications from producers or volume commitments.
- Maintain a disciplined cash distribution policy that complements our leverage, acquisition and organic growth strategies. We target leverage levels that are consistent with those of investment grade companies. We expect to maintain sufficient leverage, liquidity and other credit metrics to manage existing and future capital requirements and to take advantage of market opportunities.

Our Competitive Strengths

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

- Our vertically integrated and diversified operations, which help us generate more predictable and stable cash flows on a year-to-year basis. Our ability to provide multiple services to customers in numerous geographic areas enhances our competitive position. Our five business units are diversified by geography, customer-base and commodity sensitivities which we believe provides us with the ability to maintain cash flows throughout typical commodity cycles. For example, 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 business benefits from lower energy prices driving increased customer demand, which can offset the downward pressure on our Crude Oil Logistics and Water Solutions businesses in a low price environment.
- Our network of crude oil transportation assets, which allows us to serve customers over a wide geographic area and optimize sales. Our strategically deployed railcar fleet, towboats, barges, and trucks, and our owned and 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.

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- Our network of natural gas liquids transportation, terminal, and storage assets, which allows 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 proprietary access to refined products terminals give us the opportunity to serve customers over a large geographic area.

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

Our Businesses

Crude Oil Logistics

Overview. Our Crude Oil Logistics segment purchases crude oil from producers and transports it to refineries or for resale at pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs, and provides storage, terminaling, trucking, marine and pipeline transportation services through its owned assets. 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 Permian Basin in Texas and New Mexico, the Eagle Ford shale play in Texas, the Anadarko Basin, including the STACK, SCOOP, Granite Wash and Mississippi Lime plays in Oklahoma and Texas, and southern Louisiana at the Gulf of Mexico.

We own a 550-mile pipeline that transports crude oil from its origin in Colorado to Cushing, Oklahoma (the "Grand Mesa Pipeline"). Grand Mesa Pipeline commenced operations on November 1, 2016, and the main line portion of this pipe is comprised of a 37.5% undivided interest in a crude oil pipeline jointly owned with Saddlehorn Pipeline Company, LLC ("Saddlehorn") where we have the right to utilize 150,000 barrels per day of capacity. During the year ended March 31, 2018, there were approximately 92,000 barrels per day transported on the Grand Mesa Pipeline. Operating costs are allocated to us based on our proportionate ownership interest and throughput. We also own 970,000 barrels of operational tankage related to the Grand Mesa Pipeline.

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

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

We currently transport crude oil using the following assets:

- 163 owned trucks and 260 owned trailers operating primarily in the Mid-Continent, Permian Basin, Eagle Ford shale play, and Rocky Mountain regions;

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- 400 owned railcars and 397 leased railcars (of which 291 railcars are subleased to third parties) operating primarily in Colorado, Illinois, Kansas, Montana, Oklahoma, Texas, and Washington; and
- 10 owned towboats and 19 owned barges operating primarily in the intercoastal waterways of the Gulf Coast and along the Mississippi and Arkansas river systems.

Of our 400 owned railcars, all are compliant with the standards for railcars built subsequent to 2011. Notwithstanding this, 131 of these owned railcars have been retrofitted to meet United States Department of Transportation ("DOT") Specification 117 regulations (see "Railcar Regulation" below for a further discussion). Another 19 of these owned railcars are expected to be retrofitted by June 30, 2018. Of our 397 leased railcars, 310 are compliant with the standards for railcars built subsequent to 2011 (see Part I, Item 1A–"Risk Factors).

We contract for truck, rail, and barge transportation services from third parties and ship on 21 common carrier pipelines. We own 27 pipeline injection stations, the locations of which are summarized below.

State	Number of Pipeline Injection Stations
Texas	14
Oklahoma	6
New Mexico	5
Kansas	2
Total	27

We also have commitments on several interstate pipelines for transportation of crude oil.

We own eight storage terminal facilities. The largest of these is a terminal in Cushing, Oklahoma with a storage capacity of 3,600,000 barrels. The combined storage capacity of the other seven terminals is 1,479,400 barrels.

We lease 1,080,000 barrels of capacity at two storage terminal facilities. Of this leased storage capacity, 950,000 barrels are at Cushing, Oklahoma.

On December 22, 2017, we sold our previously held 50% interest in Glass Mountain. Glass Mountain is 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.

Customers. Our customers include crude oil refiners, producers, and marketers. During the year ended March 31, 2018, 66% of the revenues of our Crude Oil Logistics segment were generated from our ten largest customers of the segment. In addition to utilizing our assets to transport crude oil we own, we also provide truck transportation, barge transportation, storage, and terminal throughput services to our customers.

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

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

Supply. We obtain crude oil from a large base of suppliers, which consists primarily of crude oil producers. We currently purchase crude oil from approximately 200 producers at approximately 2,500 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

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of similar volumes based on similar indexes and by hedging exposure due to fluctuations in actual volumes and scheduled volumes.

Our profitability is impacted by forward crude oil prices. Crude oil markets can either be in contango (a condition in which forward crude oil prices are greater than spot prices) or can be backwardated (a condition in which forward crude oil prices are lower than spot prices). Our Crude Oil Logistics business benefits when the market is in contango, as increasing prices result in inventory holding gains during the time between when we purchase inventory and when we sell it. In addition, we are able to better utilize our storage assets when contango markets justify storing barrels. 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 these customers. We believe the following procedures enhance our collection efforts with these customers:

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

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

Water Solutions

Overview. Our Water Solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms, drilling fluids and drilling muds and performs truck and frac tank washouts. In addition, our Water Solutions segment sells the recovered hydrocarbons that result from performing these services. Our water processing facilities are strategically located near areas of high crude oil and natural gas production, including the Permian Basin in Texas and New Mexico, the DJ Basin in Colorado, the Eagle Ford shale play in Texas, the Bakken shale play in North Dakota, and the Pinedale Anticline in Wyoming. During the year ended March 31, 2018, we took delivery of 258.2 million barrels of wastewater, an average of 707,000 barrels per day.

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

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Operations. We own 75 water treatment and disposal facilities, including 100 wells. The location and permitted processing capacities of these facilities and whether the facilities are located on lands we own or lease are summarized below.

Location	Number of Facilities	Permitted Processing Capacity (barrels per day)		
		Own	Lease	Total
Permian Basin (1)(2) - Texas and New Mexico	32	1,032,500	55,000	1,087,500
Eagle Ford (1)(3) - Texas	24	515,000	291,000	806,000
DJ Basin - Colorado	12	258,000	135,000	393,000
Bakken - North Dakota	3	50,000	20,000	70,000
Pinedale Anticline (4) - Wyoming	1	—	62,500	62,500
Granite Wash (1) - Texas	2	60,000	—	60,000
Eaglebine - Texas	1	20,000	—	20,000
Total-All Facilities	75	1,935,500	563,500	2,499,000

(1) Certain facilities can dispose of both wastewater and solids such as tank bottoms, drilling fluids and drilling muds.

(2) Includes one facility with a permitted processing capacity of 20,000 barrels per day in which we own a 50% interest.

(3) Includes one facility with a permitted processing capacity of 40,000 barrels per day in which we own a 75% interest.

(4) This facility has a permitted capacity of 2,500 barrels per day and a design capacity of 60,000 barrels per day to process water to a recycle standard.

Our customers bring wastewater generated by crude oil and natural gas exploration and production operations to our facilities for treatment through pipeline gathering systems and by truck. Our pipeline delivered volumes will continue to increase as new projects come on line. Once we take delivery of the water, the level of processing is determined by the ultimate disposition of the water. Our solids customers bring solids generated by crude oil and natural gas exploration and production operations to our facilities by truck.

Our facilities in Colorado, Texas, New Mexico and North Dakota dispose of wastewater primarily into deep underground formations via injection wells.

Our facility servicing the Pinedale Anticline in Wyoming has the assets and technology needed to treat the water more extensively than a typical disposal facility. At this facility, the water is recycled, rather than being disposed of in an injection well. We process the water to the point where it can be returned to producers to be reused in future drilling operations (recycle 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 also previously treated the water to a greater extent, such that it exceeded the standards for drinking water, and could be returned to the ecosystem (discharge quality water), which operations ceased during the third quarter of fiscal year 2018. Since June 2012, we have recycled approximately 18.5 million barrels (777 million gallons) of recycle quality water, have returned approximately 9.0 million barrels (378 million gallons) of discharge quality water back to New Fork River, which is a tributary of the Colorado River, and have returned approximately 2.6 million barrels (109 million gallons) of water to the ecosystem through an agricultural irrigation system.

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

Customers. The customers of our Wyoming and Colorado facilities consist primarily of large exploration and production companies that conduct drilling operations near our facilities. The customers of our Texas and North

Dakota facilities consist of both wastewater transportation companies and producers. The primary customer of our Wyoming facility has committed to deliver a specified minimum volume of water to our facility under a long-term contract. The primary customers of our Colorado facilities have committed to deliver all wastewater produced at wells within the DJ Basin to our facilities. One customer in Texas has committed to deliver a minimum volume of 40,000 barrels of wastewater per day to our facilities. Most customers of our other facilities are not under volume commitments, although many of our facilities have acreage dedications or are connected to producer facilities by pipeline. During the year ended March 31, 2018, 16% of the water treatment and disposal revenues of our Water Solutions segment were generated from our two largest customers of the segment, and 47% of the water treatment and disposal revenues of the segment were generated from our ten largest customers of the segment.

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

Pricing Policy. We generally charge customers a fee per barrel of wastewater processed. Certain 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 exploration and production companies and also water transportation companies. We typically invoice these customers on a monthly basis. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on these customers. We believe the following procedures enhance our collection efforts with these customers:

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

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

Technology. We hold multiple patents for processing technologies. We 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 supplies the majority of the propane for our Retail Propane business as well as other retail propane businesses. 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, 2018, we sold 2.3 billion gallons of natural gas liquids, an average of 6.32 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 physical propane supply or derivatives when we have a matching purchase commitment from our wholesale customers, protect our margins and mitigate 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 or any other factors. 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.

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We also transport customer-owned natural gas liquids on our leased railcars and charge the customers a transportation service fee as well as subleasing railcars to certain customers.

We own 21 natural gas liquids terminals and we lease a fleet of approximately 4,500 high-pressure and general purpose railcars (of which 175 railcars are subleased to third parties). 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 propane, butane and asphalt operations, although we also provide transportation, storage, and throughput services to other parties to a lesser extent.

The location of the facilities and their throughput capacity are summarized below.

Facility	Throughput Capacity (gallons per day)	Terminal Interconnects
Arkansas	2,226,800	Connected to Enterprise Texas Eastern Products Pipeline; Rail Facility
Missouri	1,813,000	Connected to Phillips66 Blue Line Pipeline
Minnesota	1,441,000	Connected to Enterprise Mid-America Pipeline; Rail Facility
Indiana	1,058,000	Connected to Enterprise Texas Eastern Products Pipeline; Rail Facility
Illinois	883,000	Connected to Phillips66 Blue Line Pipeline
Wisconsin	863,000	Connected to Enterprise Mid-America Pipeline; Rail Facility
Washington	717,000	Rail Facility
Louisiana	600,000	Truck Facility
Oklahoma	600,000	Connected to Phillips66 Chisholm Pipeline; Rail Facility
Massachusetts	441,000	Rail Facility
New Mexico	408,000	Rail Facility
Montana	120,000	Rail Facility
United States Total	11,170,800	
Ontario, Canada	700,000	Truck Facility
Canada Total	700,000	
Total	11,870,800	

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 November 2022. The terminal in St. Catherines, Ontario, Canada is operated by a third party under a year-to-year agreement.

We own the land on which 14 of the 21 natural gas liquids terminals are located and we either have easements or lease the land on which the remaining 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.

We are the majority owner of an underground storage facility near Delta, Utah. This facility currently has capacity to store approximately 6.0 million barrels of natural gas liquids and refined products. We lease storage to approximately 16 customers, with lease terms ranging from one to three years. The facility is located on property for which we have a long-term lease.

We own a natural gas liquids terminal that supports refined products blending in Port Hudson, Louisiana, and a natural gas liquids and condensate facility in Kingfisher, Oklahoma. The Port Hudson Terminal is located near Baton Rouge, Louisiana, and is in proximity to other refined products infrastructure along the Colonial pipeline. This truck unloading and storage facility allows for the aggregation and supply of butane and naphtha for motor fuel blending and consists of storage tanks with total capacity of 720,000 gallons. The Kingfisher Facility is a natural gas liquids and condensate facility located in Kingfisher, Oklahoma, which is located in the middle of the STACK production region. The facility connects to the Chisholm NGL pipeline and the Conway Fractionation complex and consists of 450,000 gallons of storage capacity, a methanol extraction tower and a 5,000-barrel per day condensate splitter.

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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 Kansas, Mississippi, Missouri, Texas and Canada.

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

	Leased Storage Space (gallons)		
Storage Facility	Beginning April 1, 2018	At March 31, 2018	Storage Interconnects
Kansas	67,200,000	75,390,000	Connected to Enterprise Mid-America, NuStar Pipelines and ONEOK North System Pipeline; Rail Facility; Truck Facility
Mississippi	9,660,000	7,560,000	Connected to Enterprise Dixie Pipeline; Rail Facility
Missouri	7,560,000	7,560,000	Truck Facility
Texas	6,510,000	50,400,000	Connected to Enterprise Texas Eastern Products Pipeline; Truck Facility
Louisiana	—	6,300,000	Connected to Enlink Pipe; Rail Facility
Indiana	—	210,000	Connected to Enterprise Texas Eastern Products Pipeline; Rail Facility
United States Total	90,930,000	147,420,000	
Ontario, Canada	23,179,000	23,179,000	Rail Facility
Alberta, Canada	3,441,000	5,162,000	Connected to Cochin Pipeline; Rail Facility
Canada Total	26,620,000	28,341,000	
Total	117,550,000	175,761,000	

Customers. Our Liquids business serves approximately 900 customers in 48 states. Our Liquids business serves national, regional and independent retail, industrial, wholesale, petrochemical, refiner and natural gas liquids production customers. Our Liquids business also supplies the majority of the propane for our Retail Propane business. We deliver the propane supply to our customers at terminals located on common carrier pipelines, rail terminals, refineries, and major United States propane storage hubs. During the year ended March 31, 2018, 27% of the revenues of our Liquids segment were generated from our ten largest customers of the segment (exclusive of sales to our Retail Propane segment).

Seasonality. Our wholesale Liquids 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 of the product 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 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 are not matched with a sales commitment.

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

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

- we require certain customers to prepay or place deposits for their purchases;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;
- we require certain customers to take delivery of their contracted volume ratably to help control the account balance rather than allowing them to take delivery of propane at their discretion;
- we review receivable aging analysis 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 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 320,000 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, 2018, we sold 234.6 million gallons of propane and distillates, an average of 643,000 gallons per day. On March 30, 2018, we sold a portion of our Retail Propane segment (see "Dispositions" above), which accounted for 67.8 million gallons, or 29%, of propane sold during the year ended March 31, 2018.

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 91 customer service locations and 72 satellite distribution locations, with aggregate propane storage capacity of 13.0 million gallons and aggregate distillate storage capacity of 5.7 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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The following table summarizes the number of our customer service locations and satellite distribution locations by state:

State	Number of Customer Service Locations	Number of Satellite Distribution Locations
Georgia	27	11
Massachusetts	14	10
North Carolina	13	15
Maine	11	10
Pennsylvania	9	5
New Hampshire	6	7
Connecticut	3	3
South Carolina	2	2
Alabama	1	1
Florida	1	—
Maryland	1	1
New Jersey	1	2
Rhode Island	1	1
Tennessee	1	1
Vermont	—	3
Total	91	72

We own 57 of our 91 customer service locations and 36 of our 72 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, 2018, we owned the following propane storage tanks:

- over 300 bulk storage tanks with capacities ranging from 18,000 to 90,000 gallons; and
- over 350,000 stationary customer storage tanks with capacities ranging from 7 to 30,000 gallons.

We also lease an additional 16 bulk storage tanks ranging from 5,000 to 61,500 gallons.

At March 31, 2018, we owned a fleet of 480 bulk delivery trucks, 30 semi-tractors, 30 propane transport trailers and 475 other service trucks.

Retail deliveries of propane are usually made to customers by means of our fleet of bulk delivery trucks. Propane is pumped from the bulk delivery truck, which holds from 2,200 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 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 72% 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.

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Customers. Our retail propane and distillate customers fall into three broad categories: residential, commercial and industrial, and agricultural. At March 31, 2018, our retail propane and distillate customers were comprised of:

- 68% residential customers;
- 31% 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, 2018.

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

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

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

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

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

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

Supply. Our Retail Propane segment purchases the majority of its propane from our Liquids segment.

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 segment, 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.

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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 Anthem Propane Exchange, Brantley Gas, Coastal Energy, Downeast Energy, Eastern Propane, Gas Inc., Lumber River Propane, Osterman Propane, Proflame, Stallings Propane, Stiles Fuels, Stokes & Congleton, Carolina Energies, Triad Propane, Woodstock Gas, Yadkin Propane and Propane Services, 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. In addition, in certain storage locations, our Refined Products and Renewables segment may also purchase unfinished gasoline blending components for subsequent blending into finished gasoline to supply our marketing business as well as third parties. During the year ended March 31, 2018, we sold 108.4 million barrels of gasoline, 56.0 million barrels of diesel, 3.4 million barrels of ethanol and 2.1 million barrels of biodiesel.

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

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

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

Locations	Active Storage Capacity (shell barrels)
Southeast Facilities	
Virginia	2,791,000
Georgia	1,963,000
Mississippi	1,588,516
New Jersey	1,155,000
North Carolina	775,000
Alabama	178,000
South Carolina	166,000
Louisiana	100,000
Florida	62,000
Total Southeast Facilities Storage Capacity (1)	8,778,516
Mid-Continent Facilities	
Magellan North system	830,000
NuStar East Products system	240,000
Total Mid-Continent Facilities Storage Capacity	1,070,000
West Facilities	
Kinder Morgan (Phoenix, Arizona)	50,000
Total Facilities Storage Capacity	9,898,516

(1) Includes 1,067,900 barrels of capacity that is subleased to third parties.

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 third party terminals. We market and handle logistics for third-party ethanol manufacturers for a service fee. We primarily purchase biodiesel from production facilities in the Midwest and in Houston, Texas, and transport the biodiesel via railcar to sell to customers. We lease a total of 12,000 barrels of biodiesel storage in Deer Park, Texas and have a biodiesel terminaling agreement at a fuel terminal in Phoenix, Arizona with a minimum monthly throughput requirement. We lease 346 railcars for the transportation of renewables, of which 299 railcars are subleased to a third party.

Customers. Our Refined Products and Renewables segment serves customers in 38 states. During the year ended March 31, 2018, 35% of the revenues of our Refined Products and Renewables segment were generated from our ten largest customers of the segment. We sell to customers via rack spot sales, contract sales, bulk sales, and just-in-time sales.

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

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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 on common carrier pipelines.

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

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

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

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

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

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

Legal and Regulatory Considerations. Demand for ethanol and biodiesel is driven in large part by government mandates and incentives. Refiners and producers are required to blend a certain percentage of renewables into their refined products, although the percentage can vary from year to year based on the United States Environmental Protection Agency (“EPA”) mandates. In addition, the federal government has in recent years granted certain tax credits for the use of biodiesel, although on several occasions these tax credits have expired. In February 2018, the federal government passed a law to reinstate the tax credit retroactively to January 1, 2017, with the credit expiring on December 31, 2017. 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. Our Refined Products and Renewables customers consist primarily of commercial and industrial end users, independent retailers, distributors, marketers, government entities, and other wholesalers of refined petroleum products. We perform credit analysis, require credit approvals, establish credit limits, and follow monitoring procedures on our Refined Products and Renewables customers. We believe the following procedures enhance our collection efforts with our customers:

- we require certain customers to prepay or place deposits for our services;
- we require certain customers to post letters of credit or other forms of surety on a portion of our receivables;

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- we monitor individual customer receivables relative to previously-approved credit limits, and our automated rack delivery system gives us the option to discontinue providing product to customers when they exceed their credit limits;
- we review receivable aging analyses regularly to identify issues or trends that may develop; and
- we require our marketing personnel to manage their customers' receivable position and suspend sales to customers that have not timely paid invoices.

Trade Names. Our Refined Products and Renewables segment operates primarily under the NGL Crude Logistics and TransMontaigne Product Services LLC trade names.

Employees

At March 31, 2018, we had approximately 2,400 full-time employees. Thirty eight of our employees at three 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 Federal Energy Regulatory Commission ("FERC"), which has 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. The Grand Mesa Pipeline became operational on November 1, 2016 and has several points of origin in Colorado, runs from those origin points through Kansas and terminates in Cushing, Oklahoma. The transportation services on the Grand Mesa Pipeline are subject to FERC regulation. In February 2018, the FERC issued a revised policy to disallow income tax allowance cost recovery in rates charged by pipeline companies organized as master limited partnerships. The FERC's revised policy impacts cost-of-service rates on oil pipelines. Currently, the volumes of crude oil that are transported on the Grand Mesa Pipeline are subject to contractual agreements. Therefore, the FERC's revised policy is not expected to impact the Grand Mesa Pipeline at the present time. Additionally, contracts we enter into for the interstate transportation or storage of crude oil or natural gas may be subject to FERC regulation including reporting or other requirements. In addition, the intrastate transportation and storage of crude oil and natural gas is subject to regulation by the state in which such facilities are located, and such regulation can affect the availability and price of our supply, and have both a direct and indirect effect on our business.

Anti-Market Manipulation. We are subject to the anti-market manipulation provisions in the Natural Gas Act and the NGPA, which authorizes the FERC to impose fines of up to $1 million 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 million 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 million per day per violation or triple the monetary gain to the violator for violations of the anti-market

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manipulation sections of the Commodity Exchange Act. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation.

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

Environmental Regulation

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

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

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances such as 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 liquefied petroleum gas (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.

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

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

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

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

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

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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.

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. SPCC requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon or other constituent tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. We have discharge permits in place for a number of our facilities. These permits may require us to monitor and sample the storm water runoff from such facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

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

Hydraulic Fracturing. The underground injection of crude oil and natural gas wastes are regulated by the Underground Injection Control Program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. We do not conduct any hydraulic fracturing activities. However, a portion of our customers’ crude oil and natural gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process and our Water Solutions business treats and disposes of wastewater generated from natural gas production, including production utilizing hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate oil and gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed in recent sessions of 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. For example, Sen. Charles Van Hollen, Jr. (D-MD) introduced the Healthy Climate and Family Security Act of 2018 in the Senate on January 29, 2018 as S. 2352, and Rep. Donald Beyer (D-VA) introduced the same bill in the House of Representatives that same day as H.R. 4889. The bills would impose a cap on greenhouse gas emissions through requirement to purchase carbon permits and distribute the proceeds of such purchases to eligible individuals. 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. On May 12, 2016, the EPA finalized three rules that regulate greenhouse gas emissions from certain sources in the oil and natural gas industry, which became effective on August 2, 2016. On April 18, 2017, the EPA announced its intention to reconsider certain aspects of these rules in response to several administrative reconsideration opinions. On June 12, 2017, the EPA issued a proposed rulemaking that would stay for two years with various requirements of the rule while the EPA reconsiders them. The schedule for when this rulemaking could be finalized is not presently known. The EPA's greenhouse gas regulations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations and also could adversely affect demand for the products that we transport, store, process, or otherwise handle in connection with our services.

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

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

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

Safety and Transportation

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

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 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,

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increases the penalties for violations of pipeline safety rules, and complements the DOT's other initiatives. The 2011 Pipeline Safety Act increases the maximum fine for the most serious pipeline safety violations involving deaths, injuries or major environmental harm from $1 million to $2 million. In addition, this law established additional safety requirements for newly constructed pipelines. The law also provides for (i) additional pipeline damage prevention measures; (ii) allowing the Secretary of Transportation to require automatic and remote-controlled shut-off valves on new pipelines; (iii) requiring the Secretary of Transportation to evaluate the effectiveness of expanding pipeline integrity management and leak detection requirements; (iv) improving the way the DOT and pipeline operators provide information to the public and emergency responders; and (v) reforming the process by which pipeline operators notify federal, state and local officials of pipeline accidents. On June 22, 2016, the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 was enacted, further strengthening PHMSA's safety authority.

Railcar Regulation

We transport a significant portion of our natural gas liquids, crude oil, ethanol and biodiesel 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.

In May 2015, the DOT finalized new regulations applicable to "high hazard flammable trains." The final rule created a new North American tank car standard known as the DOT Specification 117, or DOT-117, railcar with thicker steel and redesigned bottom outlet valves, compared to the DOT-111 tank car. In addition, the adoption of additional federal, state or local laws or regulations, including any voluntary measures by the rail industry regarding railcar design or crude oil rail transport activities, or efforts by local communities to restrict or limit rail traffic involving crude oil, could similarly affect our business by increasing compliance costs and decreasing demand for our services, which could adversely affect our financial position and cash flows.

Occupational Health Regulations

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

Available Information on our Website

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

The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information about the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site (http://www.sec.gov) that contains reports, proxy and information statements and other information related to issuers that file electronically with the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

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

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We may not have sufficient cash to enable us to pay the minimum quarterly distribution. These distributions may only be made from cash available for distribution after the preferred quarterly distribution to which our preferred units are entitled. The amount of cash we can distribute on our 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, gasoline, diesel, ethanol, and biodiesel that we buy for resale and whether we are able to pass along cost increases to our customers;
- the volume of wastewater delivered to our processing facilities;
- disruptions in the availability of crude oil and/or natural gas liquids supply;
- our ability to renew leases for storage and railcars;
- the effectiveness of our commodity price hedging strategy;
- the level of competition from other energy providers; and
- prevailing economic conditions.

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

- the level of capital expenditures we make;
- the cost of acquisitions, if any;
- restrictions contained in our credit agreement (the "Credit Agreement"), the indentures governing our outstanding 5.125% senior notes due 2019, 6.875% senior notes due 2021, 7.50% senior notes due 2023, and 6.125% senior notes due 2025 (collectively, the "Indentures") and other debt service requirements;
- restrictions contained in our 10.75% Class A Convertible Preferred Units and 9.00% Class B Fixed-to-Floating Cumulative Redeemable Perpetual Preferred Unit agreements;
- 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 grow organically and complete accretive acquisitions on economically acceptable terms.

Our ability to complete accretive 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 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.

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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 acceptable 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 adversely 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.

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, debt or synergies;
- mistaken assumptions about sales volume, margin or operational expenses;
- 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 associated with a particular acquisition. Even when an issue or risk is identified, we may be unable to obtain adequate contractual protection from the seller. The realization of any of these risks could have a material adverse effect on the success of a particular acquisition or our consolidated financial position, results of operations or future growth.

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

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

At March 31, 2018, the face amount of our long-term debt was $2.7 billion. Our level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make principal and interest payments on our debt;

- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend on, among other things, our future financial and operating performance, which will be affected by prevailing economic and weather conditions, and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our future indebtedness, we would be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments

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or capital expenditures, selling assets or seeking additional equity capital. We may be unable to effect any of these actions on satisfactory terms or at all. The agreements governing our indebtedness permit us to incur additional debt under certain circumstances, and we will likely need to incur additional debt in order to implement our growth strategy. We may experience adverse consequences from increased levels of debt.

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

Our Credit Agreement 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 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 and Indentures also contain covenants requiring us to maintain certain financial ratios. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

The provisions of our Credit 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 common 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 common 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 common units, and a rising interest rate environment could have an adverse impact on our common 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.

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Our business depends on the availability of crude oil, natural gas liquids, and refined products in the United States and Canada, which is dependent on the ability and willingness of other parties to explore for and produce crude oil and natural gas. Spending on crude oil and natural gas exploration and production may be adversely affected by industry and financial market conditions that are beyond our control.

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

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

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

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

Declining crude oil prices could adversely impact our Water Solutions and Crude Oil Logistics businesses.

Crude oil spot and forward prices experienced a sharp decline during the second half of calendar year 2014. While crude oil prices have rebounded from the lows experienced during the first three months of calendar year 2016, they are still well below the prices from the first half of calendar year 2014. This has had an unfavorable impact on the revenues of our Water Solutions business. The volume of water we process is driven in part by the level of crude oil production, and the lower crude oil prices have given producers less incentive to expand production. In addition, a portion of the revenues in our Water Solutions business is generated from the sale of hydrocarbons that we recover when processing wastewater, and lower crude oil prices have an adverse impact on these revenues. A further decline in crude oil prices or a prolonged period of low crude oil prices could have an adverse effect on our Water Solutions business.

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

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

The Crude Oil Logistics, Liquids, Retail Propane, and 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

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profitability is therefore sensitive to changes in product prices caused by changes in supply, pipeline transportation and storage capacity or other market conditions.

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

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

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

We experience competition in all of our segments. In our Liquids segment, we compete for natural gas liquids 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 trucking companies 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 greater financial resources than we do to small independent retail propane distributors, agricultural cooperatives and fuel oil distributors who have entered the market due to a low barrier to entry. The actions of our retail propane and distillate competitors and the impact of imports/exports could lead to lower prices or reduced margins for the products we sell, which could have an adverse effect on our business or consolidated results of operations.

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

We can make no assurance that we will 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 or railroads we use is interrupted.

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

The fees charged to customers under our agreements with them for the transportation and marketing of crude oil, condensate, natural gas liquids, gasoline, diesel, 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 more rapidly than the fees that we charge to customers 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, gasoline, diesel, 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. 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, some of our operations are currently subject to the FERC regulations obligating us to comply with the FERC's regulations and policies applicable to those assets and operations. Other of our operations may become subject to the FERC's jurisdiction in the future (see "–Some of our operations are subject to the jurisdiction of the FERC and other operations may become subject in the future," below). Any failure on our part to comply with the FERC's regulations and policies at that time could result in the imposition of civil and criminal penalties. Failure to comply with such regulations, as interpreted and enforced, could have a material and adverse effect on our business, consolidated results of operations and financial position.

The intrastate transportation or storage of crude oil and refined products is subject to regulation by the state in which the facilities are located and transactions occur. Compliance with these state regulations could have a material and adverse effect on that portion of our business, consolidated results of operations and financial position.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") provides for statutory and regulatory requirements for derivative transactions, including crude oil, refined and renewable products, 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

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material adverse effect on our business, consolidated results of operations and financial position and ability to make cash distributions to our unitholders.

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

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

We use various modes of transportation to carry propane, distillates, crude oil, refined and renewable products and water, including trucks, railcars, barges, and pipelines, 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. Railcar accidents within the industry involving trains carrying crude oil from the Bakken region (none of which directly involved any of our business operations), have led to increased legislative and regulatory scrutiny over the safety of transporting crude oil by railcar. The introduction of 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 periods in which new railcars are constructed to meet new specifications or in which the railcars already placed in service are being retrofitted. Our barge transportation operations are subject to the Jones Act, a federal law generally restricting marine transportation in the United States to vessels built and registered in the United States, and manned/owned by United States citizens, as well as setting forth the rules and regulations of the United States Coast Guard. Non-compliance with any of these regulations could result in increased costs related to the transportation of our products and could have an adverse effect on our business.

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

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

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

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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. 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 on our customers could materially and adversely affect our utilization and profitability by reducing demand for our services. 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.

State legislation and regulatory initiatives relating to our hydraulic fracturing customers could harm our business.

Hydraulic fracturing is a frequent practice in the crude oil and natural gas fields in which our Water Solutions segment operates. Hydraulic fracturing is an important and common process used to facilitate production of natural gas and other hydrocarbon condensates in shale formations, as well as tight conventional formations. The hydraulic fracturing process is primarily regulated by state oil and gas authorities. This process has come under considerable scrutiny from sections of the public as well as environmental and other groups asserting that chemicals used in the hydraulic fracturing process could adversely affect drinking water supplies. New laws or regulations, or changes to existing laws or regulations in response to this perceived threat may adversely impact the oil and gas drilling industry. Any current or proposed 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 scrutiny from sections of the public as well as environmental and other groups asserting that the operation of certain water disposal wells has caused increased seismic activity. New laws or regulations, or changes to existing laws or regulations, in response to this perceived threat may adversely impact the water disposal industry.

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

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

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

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

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

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

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

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

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

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

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

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

Some of our operations are subject to the jurisdiction of the FERC and other operations may become subject in the future.

The FERC regulates the transportation of crude oil and refined products on interstate pipelines, among other things. Intrastate transportation and gathering pipelines that do not provide interstate services are not subject to regulation by the FERC. The distinction between the FERC-regulated interstate pipeline transportation on the one hand and intrastate pipeline transportation on the other hand, is a fact-based determination. The Grand Mesa Pipeline became operational on November 1, 2016 and has several points of origin in Colorado, runs from those origin points through Kansas and terminates in Cushing, Oklahoma. The transportation services on the Grand Mesa Pipeline are subject to FERC regulation. Other 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.

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. If the FERC’s regulatory reach was expanded to our other facilities, or if we expand our operations into areas that are subject to the FERC's regulation, we may have to commit substantial capital to comply with such regulations and such expenditures could have a material and adverse effect on our consolidated results of operations and cash flows.

Volumes of hydrocarbons 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 hydrocarbons and, therefore, our profitability.

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

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

Propane competes with other sources of energy, some of which are less costly for equivalent energy value. We compete for customers against suppliers of electricity, natural gas and fuel oil. Competition from alternative energy sources, including electricity, natural gas and renewables, has increased as a result of reduced regulation of many utilities. Electricity is a major competitor of propane, but propane in some regions has historically had 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.

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 appliances, has adversely affected the demand for propane and distillates by retail customers. Future conservation measures or technological advances in appliance efficiency, power generation or other devices may reduce demand for propane. In addition, if the price of propane increases, some of our customers may increase their conservation efforts and thereby decrease their consumption of propane.

The majority of our retail propane operations are geographically concentrated and localized warmer weather and/or economic downturns may adversely affect demand for propane, thereby affecting our financial position and results of operations.

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

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

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- the increased use of alternative fuel sources, such as battery-powered engines.

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

The United States renewables industry is highly dependent on several federal and state incentives which promote the use of renewable fuels. Without these incentives, demand for and the price of renewable fuels could be negatively impacted which could have an adverse effect on our consolidated results of operations. The most significant of the federal and state incentives which benefit renewable products we market, such as ethanol and biodiesel, is the RFS. The RFS requires that an increasing amount of renewable fuels must be blended with petroleum-based fuels each year in the United States. However, the EPA has authority to waive the requirements of the RFS, in whole or in part, if certain conditions are met. Opponents of the RFS have sought, and may continue to seek, to force the EPA to reduce or eliminate the RFS. Further, legislation has been introduced with the goal of significantly reducing or eliminating the RFS. While the outcome of these legislative efforts is uncertain, it is possible that the EPA could adjust the RFS requirements in the future. If the EPA were to adjust the RFS requirements in any material way, it could negatively impact demand for the renewable fuel products we market, which could adversely impact our consolidated results of operations.

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

The demand for biodiesel is supported by certain federal tax credits. These tax credits have typically been granted for short durations, and on several occasions these tax credits have expired. In December 2014, the federal government passed a law reinstating the tax credit retroactively to January 1, 2014 to be effective through December 31, 2014. In December 2015, the federal government re-signed the law reinstating the tax credit retroactively to January 1, 2015 to be effective through December 31, 2016. In February 2018, the federal government passed a law to reinstate the tax credit retroactively to January 1, 2017, with the credit expiring on December 31, 2017. 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.

We expect to continue to depend on key customers to support our revenues for the foreseeable future. The loss of key customers, failure to renew contracts upon expiration, or a sustained decrease in demand by key customers could result in a substantial loss of revenues and could have a material and adverse effect on our consolidated results of operations. During the year ended March 31, 2018, a significant portion of our revenues was dependent on key customers as summarized below:

- 66% of the revenues of our Crude Oil Logistics segment were generated from our ten largest customers of the segment;
- 16% of the water treatment and disposal revenues of our Water Solutions segment were generated from our two largest customers of the segment;
- 27% of the revenues of our Liquids segment were generated from our ten largest customers of the segment (exclusive of sales to our Retail Propane segment); and
- 35% of the revenues of our Refined Products and Renewables segment were generated from our ten largest customers of the segment.

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

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

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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. These expansion projects require the expenditure of significant amounts of capital, which may exceed our resources, and involve numerous regulatory, environmental, political and legal uncertainties, including political opposition by landowners, environmental activists and others. There can be no assurance that we will complete these projects on schedule or at all or at the budgeted cost. Our revenues may not increase upon the expenditure of funds on a particular project. Moreover, we may undertake expansion projects to capture anticipated future growth in production in a region in which anticipated production growth does not materialize or for which we are unable to acquire new customers. We may also rely on estimates of proved, probable or possible reserves in our decision to undertake expansion projects, which may prove to be inaccurate. As a result, our new facilities and infrastructure may not be able to attract enough product to achieve our expected investment return, which could materially and adversely affect our consolidated results of operations and financial position.

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

We may face opposition to the operation of our pipelines and facilities from environmental groups, landowners, tribal groups, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our partners and, accordingly, adversely affect our financial condition and the market price of our securities.

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 litigation, 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. Our failure to maintain adequate insurance coverage or successfully defend against product liability claims could materially and adversely affect our business, consolidated results of operations, financial position and cash flows.

A failure in our operational systems or cyber security attacks on any of our facilities, or those of third parties, may adversely affect 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 or operational 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 systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our 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 increase efficiency in our business. We use various systems in our financial and operations sectors, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, our customers and any financial data could have a material adverse effect on our business. In addition, cyber attacks on our customer and employee data may result in a financial loss, including potential fines for failure to safeguard data, and may negatively impact our reputation. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, resulting in potential liability or reputational damage or otherwise have an adverse effect on our financial results.

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We lease certain facilities and equipment and therefore are subject to the possibility of increased costs to retain necessary land and equipment use.

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

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

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

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

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

We are subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended. We are also subject to the obligation under Section 404(a) of the Sarbanes Oxley Act of 2002 to annually review and report on our internal control over financial reporting, and to the obligation under Section 404(b) of the Sarbanes Oxley Act of 2002 to engage our independent registered public accounting firm to attest to the effectiveness of our internal control 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 internal control over financial reporting, including our disclosure controls. Any failure to maintain effective internal control over financial reporting and disclosure controls could harm our operating results or cause us to fail to meet our reporting obligations. These risks may be heightened after a business combination, during the phase when we are implementing our internal control structure over the recently acquired business.

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

An impairment of goodwill and long-lived assets could reduce our earnings.

At March 31, 2018, we had goodwill and long-lived assets of $4.1 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

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wholly), requiring product deliveries over defined time periods, and credit monitoring. While we believe our procedures are effective, we can provide no assurance that bad debt write-offs in the future may not be significant and any such nonpayment problems could impact our consolidated results of operations and potentially limit our ability to make payments on our debt obligations or distributions to our unitholders.

Our terminaling operations depend on various forms of transportation for receipt and delivery of crude oil, natural gas liquids and refined products.

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

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

Our product supply is transported and stored in 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.

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, which could have a material impact on both availability and price. Terrorist attacks in the areas of our operations could negatively impact our ability to transport propane to our locations. These risks could potentially negatively impact our consolidated results of operations.

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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 common 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 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:

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- 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.

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.

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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

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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;
- 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.

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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 our unitholders 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 nonrecourse 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.

The 10.75% Class A Convertible Preferred Units ("Class A Preferred Units") and 9.00% Class B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units ("Class B Preferred Units") (collectively the "Preferred Units") give the holders thereof liquidation and distribution preferences over our common unitholders.

In June 2016, we issued 19,942,169 Class A Preferred Units and in June 2017, we issued 8,400,000 Class B Preferred Units, which rank senior to the common units with respect to distribution rights and rights upon liquidation. Subject to certain exceptions, as long as any Preferred Units remain outstanding, we may not declare any distribution on our common units unless all accumulated and unpaid distributions have been declared and paid on the Preferred Units. In the event of our liquidation, winding-up or dissolution, the holders of the Preferred Units would have the right to receive proceeds from any such transaction before the holders of the common units. The payment of the liquidation preference could result in common unitholders not receiving any consideration if we were to liquidate, dissolve or wind up, either voluntarily or involuntarily. Additionally, the existence of the liquidation preference may reduce the value of the common units, make it harder for us to sell common units in offerings in the future, or prevent or delay a change of control.

The Class A Preferred Units give the holders thereof certain rights relating to our business and management, and the ability to convert such units into our common units, potentially causing dilution to our common unitholders.

In connection with the issuance of the Class A Preferred Units, we entered into an agreement with Oaktree Capital Management L.P. ("Oaktree") pursuant to which we granted them the right to appoint one member to the board of directors of our general partner. In addition, the holders of the Class A Preferred Units have the right to vote, under certain conditions, on an as-converted basis with our common unitholders on matters submitted to a unitholder vote. Also, as long as any Class A Preferred Units are outstanding, subject to certain exceptions, the affirmative vote or consent of the holders of at least a majority of the outstanding Class A Preferred Units, voting together as a separate class, will be necessary for effecting or validating, among other things: (i) any action to be taken that adversely affects any of the rights, preferences or privileges of the Class A Preferred Units, (ii) amending the terms of the Class A Preferred Units, (iii) the issuance of any additional Class A Preferred Units or equity security senior in right of distribution or in liquidation to the Class A Preferred Units, (iv) any issuance of preferred equity securities by any of our consolidated controlled subsidiaries of any issued or authorized amount of, any specific class or series of securities, (v) any issuance by us of parity units, subject to certain exceptions and (vi) the ability to incur funded indebtedness for borrowed money if pro forma for such incurrence, the leverage ratio (as defined in the Credit

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Agreement) would exceed 5.50. These restrictions may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Furthermore, the conversion of the Class A Preferred Units into common units, as early as three years from the issuance date of the Class A Preferred Units, may cause substantial dilution to holders of the common units. Because the board of directors of our general partner is entitled to designate the powers and preferences of Class A Preferred Units without a vote of our unitholders, subject to New York Stock Exchange rules and regulations, our unitholders will have no control over what designations and preferences our future preferred units, if any, will have.

The issuance of common units upon exercise of the warrants may cause dilution to existing common unitholders and may place downward pressure on the trading price of our common units.

In connection with our issuance of Class A Preferred Units in June 2016, we issued warrants exercisable into a maximum of 4,375,112 common units, with an exercise price of $0.01 per common unit. One-third of the warrants are exercisable beginning on or after the first anniversary of the original issue date, another one-third of the warrant units from and after the second anniversary of the original issue date and the final one-third may be converted from and after the third anniversary. The future exercise of the warrants by the holders of those securities may cause a reduction in the relative voting power and percentage ownership interests of our other common unitholders, and may place downward pressure on the trading price of our common units.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. We could lose our status as a partnership for a number of reasons, including not having enough “qualifying income.” If the Internal Revenue Service (“IRS”) were to treat us as a corporation for federal income tax purposes, our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently 21% (changed from 35% under the recently enacted tax reform law), and would likely pay state and local 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, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the market value of our common units.

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

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Our unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, our unitholders are entitled to a deduction for the interest we have paid or accrued on indebtedness properly allocable to our business during our taxable year. However, under the Tax Cuts and Jobs Act of 2017 (the “Act”) signed into law by the President of the United States on December 22, 2017, beginning in tax year 2018, the deductibility of net interest expense is limited to 30% of our adjusted taxable income. For tax years beginning after December 31, 2017 and before January 1, 2022, the Act calculates adjusted taxable income using an EBITDA-based calculation. For tax years beginning January 1, 2022 and thereafter, the calculation of adjusted taxable income will not add back depreciation or amortization. Any disallowed business interest expense is then generally carried forward as a deduction in a succeeding taxable year at the partner level. These limitations might cause interest expense to be deducted by our unitholders in a later period than recognized in the GAAP financial statements.

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 Congress propose and consider substantive changes to the existing United States federal income tax laws that affect the tax treatment of publicly traded partnerships, including as a result of any fundamental tax reform.

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

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

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

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If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case our cash available for distribution to our unitholders could be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so under all circumstances. If we are required to make payments of taxes, penalties and interest resulting from audit adjustments, our cash available for distribution to our unitholders could be substantially reduced.

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

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

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

If unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of the unitholder's allocable share of our net taxable income decrease the unitholder's tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units the unitholder sells will, in effect, become taxable income to the unitholder if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized on any sale of common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sell units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

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

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

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

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

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

We prorate our items of income, gain, loss and deduction for United States federal income tax purposes between transferors and transferees of our units each month based on the ownership of our units on the first business 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 business day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of the Treasury recently adopted final Treasury Regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such regulations do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to challenge our proration method, 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 effect 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 a 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 those common units, the unitholder would no longer be treated for federal income 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 a gain or loss from the 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.

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

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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

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 obligation under our revolving credit facility is 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 is operating with all but one of the required permits, as the state of Wyoming has not yet developed a process for issuing permits of this type. We believe that the permit will ultimately be granted, but we are unable to determine the timing of any action by the state of Wyoming.

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

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

Item 3. Legal Proceedings

We are involved from time to time in various legal proceedings and claims arising in the ordinary course of business. For information related to legal proceedings, see the discussion under the captions "Legal Contingencies" and "Environmental Matters" in Note 9 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, 2018, there were approximately 150 common unitholders of record which does not include unitholders for whom common units may be held in "street name."

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

	Price Range		Cash
	High	Low	Distribution
2018 Fiscal Year			
Fourth Quarter	$17.65	$10.00	$ 0.3900
Third Quarter	$14.75	$10.07	$ 0.3900
Second Quarter	$14.78	$8.57	$ 0.3900
First Quarter	$23.19	$11.53	$ 0.3900
2017 Fiscal Year			
Fourth Quarter	$25.80	$20.56	$ 0.3900
Third Quarter	$21.50	$14.65	$ 0.3900
Second Quarter	$20.00	$16.75	$ 0.3900
First Quarter	$20.06	$7.10	$ 0.3900

Cash Distribution Policy

Available Cash

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

General Partner Interest

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

Incentive Distribution Rights

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

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

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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 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). In addition, quarterly distributions on the preferred units must be fully paid for all preceding fiscal quarters before we are permitted to declare or pay any distributions on our common units.

Sales of Unregistered Securities

We did not sell our equity securities in unregistered transactions during the year ended March 31, 2018.

Common Unit Repurchase Program

The following table sets forth certain information with respect to repurchases of common units during the three months ended March 31, 2018:

Period	Total Number of Common Units Purchased	Average Price Paid Per Common Unit	Total Number of Common Units Purchased as Part of Publicly Announced Program	Approximate Dollar Value of Common Units that May Yet Be Purchased Under the Program
January 1-31, 2018	—	$ —	—	$ —
February 1-28, 2018	15,848	$ 13.18	—	$ —

March 1-31, 2018	—	$ —	—	$ —
	15,848		—	$ —

The common units were surrendered by employees to pay tax withholding in connection with the vesting of restricted common units. As a result, we are deeming the surrenders to be “repurchases.” These repurchases were not part of a publicly announced program to repurchase our common units, nor do we currently have a publicly announced program to repurchase our common units.

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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. See Part III, Item 12–"Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters–Securities Authorized for Issuance Under Equity Compensation Plan" which is incorporated by reference into this Item 5.

Item 6. Selected Financial Data

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

The selected consolidated historical financial data at March 31, 2018 and 2017, and for each of the three years in the period ended March 31, 2018 is derived from our audited historical consolidated financial statements included in this Annual Report. The selected consolidated historical financial data at March 31, 2016, 2015 and 2014 and for each of the two years in the period ended March 31, 2015 is derived from our audited historical consolidated financial statements not included in this Annual Report.

	Year Ended March 31,				
	2018	2017	2016	2015	2014
	(in thousands, except per unit data)				
Income Statement Data					
Total revenues	$17,282,718	$13,022,228	$11,742,110	$16,802,057	$9,699,274
Total cost of sales	$16,536,038	$12,321,909	$10,839,037	$15,958,207	$9,132,699
Operating income (loss)	$138,257	$255,083	$(104,603)	$107,420	$106,565
Interest expense	$199,570	$150,478	$133,089	$110,123	$58,854
Loss (gain) on early extinguishment of liabilities, net	$23,201	$(24,727)	$(28,532)	$—	$—
Net (loss) income attributable to NGL Energy Partners LP	$(70,875)	$137,042	$(198,929)	$37,306	$47,655
Basic (loss) income per common unit	$(1.08)	$0.99	$(2.35)	$(0.05)	$0.51
Diluted (loss) income per common unit	$(1.08)	$0.95	$(2.35)	$(0.05)	$0.51
Cash Flows Data					
Net cash provided by (used in) operating activities	$137,642	$(24,240)	$351,495	$262,391	$85,236
Net cash provided by (used in) investing activities	$270,582	$(363,126)	$(445,327)	$(1,366,221)	$(1,455,373)
Net cash (used in) provided by financing activities	$(394,281)	$371,454	$80,705	$1,134,693	$1,369,016
Cash distributions paid per common unit	$1.56	$1.56	$2.54	$2.37	$2.01
Balance Sheet Data - Period End					
Total assets	$6,151,122	$6,320,379	$5,560,155	$6,655,792	$4,134,910
Total long-term obligations, exclusive of debt issuance costs and current maturities	$2,856,142	$3,148,017	$3,160,073	$2,842,493	$1,628,173
Total equity	$2,086,095	$2,166,802	$1,694,065	$2,693,432	$1,531,853

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

Overview

We are a Delaware limited partnership ("we," "us," "our," or the "Partnership") formed in September 2010. NGL Energy Holdings LLC serves as our general partner. On May 17, 2011, we completed our initial public offering ("IPO"). Subsequent to our IPO, we significantly expanded our operations through numerous acquisitions as discussed in Part I, Item 1–"Business–Acquisitions." At March 31, 2018, our operations include:

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

Crude Oil Logistics

Our Crude Oil Logistics segment purchases crude oil from producers and transports it to refineries or for resale at pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs, and provides storage, terminaling, trucking, marine and pipeline transportation services through its owned assets.

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

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

	Crude Oil Spot Price Per Barrel		
Year Ended March 31,	Low	High	At Period End
2018	$42.53	$66.14	$ 64.94
2017	$35.70	$54.45	$ 50.60
2016	$26.21	$61.43	$ 38.34

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

Our Crude Oil Logistics segment generated operating income of $122.9 million during the year ended March 31, 2018, which included a gain of $108.6 million on the sale of our previously held 50% interest in Glass Mountain Pipeline, LLC ("Glass Mountain"). Our Crude Oil Logistics segment generated an operating loss of $17.5 million during the year ended March 31, 2017.

Water Solutions

Our Water Solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms, drilling fluids and drilling muds and performs truck and frac tank washouts. In addition, our Water Solutions segment sells the recovered hydrocarbons that result from performing these services.

Our water processing facilities are strategically located near areas of high crude oil and natural gas production. A significant factor affecting the profitability of our Water Solutions segment is the extent of exploration and production in the areas near our facilities, which is generally based upon producers' expectations about the profitability of drilling new wells. The

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primary customer of our Wyoming facility has committed to deliver a specified minimum volume of water to our facility under a long-term contract. The primary customers of our Colorado facilities have committed to deliver all wastewater produced at wells within the DJ Basin to our facilities. One customer in Texas has committed to deliver a minimum volume of 40,000 barrels of wastewater per day to our facilities. Most customers of our other facilities are not under volume commitments, although many of our facilities have acreage dedications or are connected to producer facilities by pipeline.

Our Water Solutions segment generated an operating loss of $24.2 million during the year ended March 31, 2018. Our Water Solutions segment generated operating income of $44.6 million during the year ended March 31, 2017, which included an adjustment of $124.7 million to the previously recorded $380.2 million estimated goodwill impairment charge recorded during the three months ended March 31, 2016 (see Note 6 to our consolidated financial statements included in this Annual Report).

Liquids

Our Liquids segment purchases propane, butane, and other products from refiners, processing plants, producers, and other parties, and sells the products to retailers, wholesalers, refiners, and petrochemical plants throughout the United States and in Canada. Our Liquids segment owns 21 terminals throughout the United States and a salt dome storage facility joint venture in Utah, operates a fleet of leased railcars, and leases underground storage capacity. See Note 15 to our consolidated financial statements included in this Annual Report for a discussion of the joint venture of our Sawtooth NGL Caverns, LLC (“Sawtooth”) business. We attempt to reduce our exposure to price fluctuations by using back-to-back physical contracts and pre-sale agreements that allow us to lock in a margin on a percentage of our winter volumes. We also enter into financially settled derivative contracts as economic hedges of our physical inventory, physical sales and physical purchase contracts.

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

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

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

	Conway, Kansas Propane Spot Price Per Gallon			Mt. Belvieu, Texas Propane Spot Price Per Gallon		
Year Ended March 31,	Low	High	At Period End	Low	High	At Period End
2018	$ 0.53	$ 0.98	$ 0.66	$ 0.57	$ 1.02	$ 0.80
2017	$ 0.35	$ 0.89	$ 0.56	$ 0.42	$ 0.93	$ 0.61
2016	$ 0.27	$ 0.51	$ 0.39	$ 0.30	$ 0.57	$ 0.44

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

	Butane Spot Price Per Gallon		
Year Ended March 31,	Low	High	At Period End
2018	$ 0.64	$ 1.12	$ 0.78

2017	$ 0.52	$ 1.42	$ 0.75
2016	$ 0.42	$ 0.68	$ 0.53

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

Our Liquids segment generated an operating loss of $93.1 million during the year ended March 31, 2018, which included a goodwill impairment charge of $116.9 million related to our salt dome storage facility joint venture in Utah (see

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Note 6 to our consolidated financial statements included in this Annual Report). Our Liquids segment generated operating income of $43.3 million during the year ended March 31, 2017.

Retail Propane

Our Retail Propane segment is a “cost-plus” business that sells propane, distillates, equipment and supplies to end users consisting of residential, agricultural, commercial, and industrial customers and to certain resellers in 21 states and the District of Columbia. Our Retail Propane segment purchases the majority of its propane from our Liquids segment. See Note 15 to our consolidated financial statements included in this Annual Report for a discussion of the sale of a portion of our Retail Propane segment. Our Retail Propane segment generates margins based on the difference between the wholesale cost of a product and the selling price of the product in the retail markets. These margins fluctuate over time due to supply and demand conditions. Weather conditions can have a significant impact on our sales volumes and prices, as a large portion of our sales are to residential customers who purchase propane and distillates for home heating purposes.

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

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

Our Retail Propane segment generated operating income of $155.6 million during the year ended March 31, 2018, which included a gain of $89.3 million on the sale of a portion of our Retail Propane segment. Our Retail Propane segment generated operating income of $49.3 million during the year ended March 31, 2017.

Refined Products and Renewables

Our Refined Products and Renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations, purchases refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedules them for delivery at various locations throughout the country. In addition, in certain storage locations, our Refined Products and Renewables segment may also purchase unfinished gasoline blending components for subsequent blending into finished gasoline to supply our marketing business as well as third parties. 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 terminals owned by third parties.

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

	Gasoline Spot Price Per Barrel		
Year Ended March 31,	Low	High	At Period End
2018	$59.24	$89.88	$ 84.75
2017	$53.44	$71.40	$ 71.40
2016	$37.75	$90.15	$ 59.91

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

	Diesel Spot Price Per Barrel		
Year Ended March 31,	Low	High	At Period End
2018	$57.32	$89.71	$ 85.19
2017	$45.13	$71.58	$ 66.09
2016	$36.36	$84.68	$ 49.76

Our Refined Products and Renewables segment generated operating income of $56.7 million during the year ended March 31, 2018. Our Refined Products and Renewables segment generated operating income of $222.5 million during the year

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ended March 31, 2017, which included a gain of $104.1 million on the sale of all of the TransMontaigne Partners L.P. ("TLP") common units we owned during the year ended March 31, 2017.

Consolidated Results of Operations

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

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
Total revenues	$17,282,718	$13,022,228	$11,742,110
Total cost of sales	16,536,038	12,321,909	10,839,037
Operating expenses	330,857	307,925	401,118
General and administrative expense	109,451	116,566	139,541
Depreciation and amortization	252,712	223,205	228,924
(Gain) loss on disposal or impairment of assets, net	(105,313)	(209,177)	320,766
Revaluation of liabilities	20,716	6,717	(82,673)
Operating income (loss)	138,257	255,083	(104,603)
Equity in earnings of unconsolidated entities	7,964	3,084	16,121
Revaluation of investments	—	(14,365)	—
Interest expense	(199,570)	(150,478)	(133,089)
(Loss) gain on early extinguishment of liabilities, net	(23,201)	24,727	28,532
Other income, net	8,403	27,762	5,575
(Loss) income before income taxes	(68,147)	145,813	(187,464)
Income tax (expense) benefit	(1,458)	(1,939)	367
Net (loss) income	(69,605)	143,874	(187,097)
Less: Net income attributable to noncontrolling interests	(240)	(6,832)	(11,832)
Less: Net income attributable to redeemable noncontrolling interests	(1,030)	—	—
Net (loss) income attributable to NGL Energy Partners LP	(70,875)	137,042	(198,929)
Less: Distributions to preferred unitholders	(59,697)	(30,142)	—
Less: Net income allocated to general partner	(5)	(232)	(47,620)
Less: Repurchase of warrants	(349)	—	—
Net (loss) income allocated to common unitholders	$(130,926)	$106,668	$(246,549)

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, disposals and other transactions.

Trends

Crude oil prices can fluctuate widely based on changes in supply and demand conditions. The opportunity to generate revenues in our Crude Oil Logistics business is heavily influenced by the volume of crude oil being produced. Crude oil prices declined sharply during the period from July 2014 through February 2016. Crude oil prices have rebounded and at March 31, 2018, the spot price for NYMEX West Texas Intermediate Crude Oil at Cushing, Oklahoma was $64.94 per barrel. While crude oil production in the United States has been strong in recent years, a sharp decline in crude oil prices could reduce the incentive for producers to expand production. Low crude oil prices could result in declines in crude oil production and may adversely impact volumes and margins in our Crude Oil Logistics business. Crude oil price declines have had an adverse impact on many participants in the energy markets, and the inherent risk of customer or counterparty nonperformance is higher when crude oil prices are low or in decline.

From January 2015 to January 2018, crude oil markets were in contango, a condition in which forward crude oil prices are greater than spot prices. Our Crude Oil Logistics business benefits when the market is in contango, as increasing prices result in inventory holding gains during the time between when we purchase inventory and when we sell it. In addition, we are

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able to better utilize our storage assets when contango markets justify storing barrels. Beginning in February 2018, crude oil markets have shifted to being flat to backwardated, a condition in which forward crude oil prices are lower than spot prices. When markets are backwardated, falling prices typically have an unfavorable impact on our margins.

Our opportunity to generate revenues in our Water Solutions business is based on the level of production of natural gas and crude oil in the areas where our facilities are located. As described above, crude oil prices declined sharply since July 2014 but have increased since March 31, 2016. Also, drilling rigs and production have increased since March 31, 2016, particularly in the Permian and DJ Basins which has positively impacted the volumes of our Water Solutions business (during the three months ended March 31, 2018 we processed 761,000 barrels of wastewater per day, compared to 536,000 barrels of wastewater per day during the three months ended March 31, 2017). A portion of the revenues in our Water Solutions business is generated from the sale of hydrocarbons that we recover when processing wastewater. These recovered hydrocarbon revenues have increased due primarily to an increase in the volume of wastewater processed, an increase in the amount of hydrocarbons per barrel of wastewater processed and an increase in crude oil prices, which have resulted in higher per-barrel revenues for our Water Solutions business.

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

During the year ended March 31, 2018, prices for refined products increased. Gulf Coast prices, on which our sales contracts are based, increased less than the New York Harbor prices, on which our futures contracts are based, which had an unfavorable impact on our cost of sales. Based on historical experience, we generally expect the spreads between Gulf Coast and New York Harbor prices to be more consistent over the course of a contract year than during any individual quarter within the year, and that we should expect more volatility in cost of sales among quarters within a fiscal year than we would expect during a full fiscal year.

Seasonality

Seasonality impacts our Liquids, Retail Propane and Refined Products and Renewables 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 our Liquids and Retail Propane businesses, revenues, operating profits and operating cash flows are generated mostly in the third and fourth quarters of our fiscal year. The seasonal motor fuel blend during the third quarter of our fiscal year impacts the value of our gasoline inventory in our Refined Products and Renewables business and also represents a period when we build inventory into our system. We borrow under our Revolving Credit Facility to supplement our operating cash flows during the periods in which we are building inventory. See "–Liquidity, Sources of Capital and Capital Resource Activities–Cash Flows."

Recent Developments

Transactions during the Three Months Ended March 31, 2018

Repurchases of Senior Unsecured Notes

During the three months ended March 31, 2018, we repurchased $7.4 million of the 2019 Notes (as defined herein), $40.6 million of the 2023 Notes (as defined herein) and $23.4 million of the 2025 Notes (as defined herein). See Note 8 to our consolidated financial statements included in this Annual Report for further discussion on the repurchases.

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Credit Agreement

On March 6, 2018, we amended our Credit Agreement. In the amendment, the lenders consented to, subject to the consummation of the initial Sawtooth disposition, release each Sawtooth entity from its guaranty and other obligations under the loan documents. In return, the Partnership agreed to use the net proceeds of each Sawtooth disposition to pay down existing indebtedness no later than five business days after the consummation of such Sawtooth disposition.

Subsequent Events

On May 24, 2018, we amended our Credit Agreement to, among other things, modify our interest coverage ratio financial covenant for periods beginning March 31, 2018 and thereafter and to add a total leverage indebtedness ratio covenant, to be measured beginning March 31, 2019. Additionally, the amendment specifies that, should our leverage ratio be greater than 4.00 to 1 with respect to the quarter ended September 30, 2018, commitments under our Expansion Capital Facility will be decreased, immediately and permanently by $100.0 million.

See Note 8 to our consolidated financial statements included in this Annual Report for a further description of our Credit Agreement.

Acquisitions

As discussed below, we completed numerous acquisitions during the years ended March 31, 2018 and 2017. These acquisitions impact the comparability of our results of operations between our current and prior fiscal years.

During the year ended March 31, 2018, in our Water Solutions segment, we acquired the remaining 50% ownership interest in NGL Solids Solutions, LLC, and in our Retail Propane segment, we acquired seven retail propane businesses and certain assets from an equity method investee. See Note 4 and Note 13 to our consolidated financial statements included in this Annual Report for a further discussion.

During the year ended March 31, 2017, we acquired:

- three water solutions facilities;
- the remaining 25% ownership interest in three water solutions facilities;
- an additional 24.5% interest in NGL Water Pipelines, LLC;
- the remaining 65% ownership interest in Grassland Water Solutions, LLC (“Grassland”), in which we subsequently sold 100% of our interest;
- four retail propane businesses; and
- certain natural gas liquids facilities.

Subsequent Events

See Note 17 to our consolidated financial statements included in this Annual Report for a further discussion of the acquisitions that occurred subsequent to March 31, 2018.

Dispositions

Sale of a Portion of Retail Propane Business

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC LPG for net proceeds of $212.4 million in cash at closing, and recorded a gain on disposal of $89.3 million during the year ended March 31, 2018. The Retail Propane businesses subject to this transaction consisted of our operations across the Mid-Continent and Western portions of the United States, including three of the seven retail propane businesses we acquired during the year ended March 31, 2018. We retained our Retail Propane businesses located in the Eastern, mid-Atlantic and Southeastern sections of the United States. See Note 15 to our consolidated financial statements included in this Annual Report for a further discussion.

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As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Retail Propane segment have not been classified as discontinued operations.

Sawtooth Joint Venture

On March 30, 2018, we completed the transaction to form a joint venture with Magnum Liquids, LLC, a portfolio company of Haddington Ventures LLC, along with Magnum Development, LLC and other Haddington-sponsored investment entities (collectively "Magnum") to focus on the storage of natural gas liquids and refined products by combining our Sawtooth salt dome storage facility with Magnum's refined products rights and adjacent leasehold. Magnum acquired an approximately 28.5% interest in Sawtooth from us, in exchange for consideration consisting of a cash payment of approximately $37.6 million (excluding working capital) and the contribution of certain refined products rights and adjacent leasehold. The disposition of this interest was accounted for as an equity transaction, no gain or loss was recorded and the carrying value of the noncontrolling interest was adjusted to reflect the change in ownership interest of the subsidiary. We own approximately 71.5% of the joint venture; and within the next three years, Magnum has options to acquire our remaining interest for an additional $182.4 million. See Note 15 to our consolidated financial statements included in this Annual Report for a further discussion.

Sale of Interest in Glass Mountain

On December 22, 2017, we sold our previously held 50% interest in Glass Mountain for net proceeds of $292.1 million and recorded a gain on disposal of $108.6 million during the three months ended December 31, 2017. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Crude Oil Logistics segment have not been classified as discontinued operations.

Subsequent Events

See Note 17 to our consolidated financial statements included in this Annual Report for a further discussion of the dispositions that occurred subsequent to March 31, 2018.

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Segment Operating Results for the Years Ended March 31, 2018 and 2017

Crude Oil Logistics

The following table summarizes the operating results of our Crude Oil Logistics segment for the periods indicated:

	Year Ended March 31,		
	2018	2017	Change
	(in thousands, except per barrel amounts)		
Revenues:			
Crude oil sales	$2,151,203	$1,603,667	$547,536
Crude oil transportation and other	122,786	70,027	52,759
Total revenues (1)	2,273,989	1,673,694	600,295
Expenses:			
Cost of sales-excluding impact of derivatives	2,120,640	1,573,246	547,394
Cost of sales-derivative loss	7,021	5,579	1,442
Operating expenses	47,846	41,535	6,311
General and administrative expenses	6,584	5,961	623
Depreciation and amortization expense	80,387	54,144	26,243
(Gain) loss on disposal or impairment of assets, net	(111,393)	10,704	(122,097)
Total expenses	2,151,085	1,691,169	459,916
Segment operating income (loss)	$122,904	$(17,475)	$140,379
Crude oil sold (barrels)	39,626	34,212	5,414
Crude oil transported on owned pipelines (barrels)	33,454	6,365	27,089
Crude oil storage capacity - owned and leased (barrels) (2)	6,159	7,024	(865)
Crude oil storage capacity leased to third parties (barrels) (2)	2,641	3,717	(1,076)
Crude oil inventory (barrels) (2)	1,219	2,844	(1,625)
Crude oil sold ($/barrel)	$54.288	$46.874	$7.414
Cost per crude oil sold ($/barrel)	$53.694	$46.148	$7.546
Crude oil product margin ($/barrel)	$0.594	$0.726	$(0.132)

(1) Revenues include $13.9 million and $6.8 million of intersegment sales during the years ended March 31, 2018 and 2017, respectively, that are eliminated in our consolidated statements of operations.
(2) Information is presented as of March 31, 2018 and March 31, 2017, respectively.

Crude Oil Sales Revenues. The increase was due primarily to an increase in crude oil prices and sales volumes during the year ended March 31, 2018, compared to the year ended March 31, 2017. This segment continued to be impacted by competition and low margins in the majority of the basins across the United States and we continue to market crude volumes in these basins to support our various pipeline, terminal and transportation assets. Additionally, we bear the cost of certain minimum volume commitments on third-party crude oil pipelines in various basins which are currently not profitable.

Crude Oil Transportation and Other Revenues. The increase was due primarily to our Grand Mesa Pipeline becoming operational on November 1, 2016 which increased revenues by $55.0 million during the year ended March 31, 2018, compared to the year ended March 31, 2017. The increase was also due to increased volumes related to production growth in the DJ Basin. During the year ended March 31, 2018, approximately 33.5 million barrels of crude oil were transported on the Grand Mesa Pipeline, which averaged approximately 92,000 barrels per day and financial volumes averaged approximately 96,000 barrels per day (volume amounts are from both internal and external parties). Higher revenues in our trucking operations during the year ended March 31, 2018 were due primarily to increased demand for transportation services, compared to the year ended March 31, 2017, and were partially offset by the flattening of the contango curve for crude oil (a condition in which forward crude oil prices are greater than spot prices) during the year ended March 31, 2018, compared to the year ended March 31, 2017.

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Cost of Sales-Excluding Impact of Derivatives. The increase was due primarily to an increase in crude oil prices during the year ended March 31, 2018, compared to the year ended March 31, 2017.

Cost of Sales-Derivatives. Our cost of sales during the year ended March 31, 2018 was increased by $4.2 million of net realized losses on derivatives and $2.8 million of net unrealized losses on derivatives. Our cost of sales during the year ended March 31, 2017 was increased by $7.1 million of net realized losses on derivatives and reduced by $1.5 million of net unrealized gains on derivatives.

Operating and General and Administrative Expenses. The increase was due primarily to our Grand Mesa Pipeline becoming operational on November 1, 2016 which increased expenses by $8.0 million during the year ended March 31, 2018, compared to the year ended March 31, 2017. This increase was partially offset by lower repair and maintenance expense associated with having a newer fleet of barges and a smaller fleet of trucks, as well as the timing of repairs, and lower property taxes due to decreased inventory.

Depreciation and Amortization Expense. The increase was due primarily to our Grand Mesa Pipeline becoming operational on November 1, 2016 which increased depreciation and amortization expense by $23.0 million during the year ended March 31, 2018, compared to the year ended March 31, 2017. Also contributing to the increase was higher depreciation expense related to other capital projects being placed into service.

(Gain) Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2018, we recorded a gain of $108.6 million on the sale of our previously held 50% interest in Glass Mountain (see Note 2 to our consolidated financial statements included in this Annual Report). In addition, we recorded a net gain of $2.8 million on the sales of excess pipe and certain other assets. During the year ended March 31, 2017, we recorded a net loss of $6.5 million on the sales of certain assets and a loss of $4.2 million due to the write-down of certain other assets.

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Water Solutions

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

	Year Ended March 31,		
	2018	2017	Change
	(in thousands, except per barrel and per day amounts)		
Revenues:			
Service fees	$149,114	$110,049	$39,065
Recovered hydrocarbons	58,948	31,103	27,845
Other revenues	21,077	18,449	2,628
Total revenues	229,139	159,601	69,538
Expenses:			
Cost of sales-excluding impact of derivatives	2,150	2,071	79
Cost of sales-derivative loss	17,195	1,997	15,198
Operating expenses	105,200	85,562	19,638
General and administrative expenses	2,623	2,469	154
Depreciation and amortization expense	98,623	101,758	(3,135)
Loss (gain) on disposal or impairment of assets, net	6,863	(85,560)	92,423
Revaluation of liabilities	20,716	6,717	13,999
Total expenses	253,370	115,014	138,356
Segment operating (loss) income	$(24,231)	$44,587	$(68,818)
Wastewater processed (barrels per day)			
Eagle Ford Basin	235,713	208,649	27,064
Permian Basin	289,360	184,702	104,658
DJ Basin	113,771	68,253	45,518
Other Basins	68,466	40,185	28,281
Total	707,310	501,789	205,521
Solids processed (barrels per day)	5,662	3,056	2,606
Skim oil sold (barrels per day)	3,210	1,989	1,221
Service fees for wastewater processed ($/barrel)	$0.58	$0.60	$(0.02)
Recovered hydrocarbons for wastewater processed ($/barrel)	$0.23	$0.17	$0.06
Operating expenses for wastewater processed ($/barrel)	$0.41	$0.47	$(0.06)

Service Fee Revenues. The increase was due primarily to an increase in the volume of wastewater processed, partially offset by higher volumes in areas with lower fees. We continue to benefit from the increased rig counts as compared to the prior year in the basins in which we operate, particularly in the Permian Basin.

Recovered Hydrocarbon Revenues. The increase was due primarily to an increase in the volume of wastewater processed, an increase in the amount of hydrocarbons per barrel of wastewater processed and an increase in crude oil prices.

Other Revenues. Other revenues primarily include solids disposal revenues and water pipeline revenues, both of which increased during the year ended March 31, 2018 due to increased volumes. These increases were partially offset by a decrease in freshwater revenues due to the sale of Grassland in November 2016 (see below discussion of the loss on the sale of Grassland).

Cost of Sales-Excluding Impact of Derivatives. Cost of sales-excluding impact of derivatives, which primarily includes expenses to bring wastewater to certain of our water solutions facilities, was consistent between the current year and prior year.

Cost of Sales-Derivatives. We enter into derivatives in our Water Solutions segment to protect against the risk of a decline in the market price of the hydrocarbons we expect to recover when processing the wastewater and selling the skim oil. Our cost of sales during the year ended March 31, 2018 included $13.7 million of net unrealized losses on derivatives and $3.5

million of net realized losses on derivatives. Our cost of sales during the year ended March 31, 2017 included $4.1 million of net realized losses on derivatives and the reversal of $2.1 million of net unrealized losses on derivatives at March 31, 2016 as there were no open derivatives at March 31, 2017.

Operating and General and Administrative Expenses. The increase was due primarily to higher costs of operations of water disposal wells due to higher volumes processed, partially offset by cost reduction efforts. Due to the higher volumes processed, our cost per barrel has decreased, as shown in the table above.

Depreciation and Amortization Expense. The decrease was due primarily to lower amortization expense from the write-off of an intangible asset during the year ended March 31, 2017 as well as certain intangible assets being fully amortized during the year ended March 31, 2017, partially offset by acquisitions and developed facilities (see Note 7 to our consolidated financial statements included in this Annual Report).

Loss (Gain) on Disposal or Impairment of Assets, Net. During the year ended March 31, 2018, we recorded a loss of $8.2 million on the disposals of certain assets, partially offset by a gain of $1.3 million for the termination of a non-compete agreement, which included the carrying value of the non-compete agreement intangible asset that was written off (see Note 7 to our consolidated financial statements included in this Annual Report).

During the year ended March 31, 2017, we recorded:

- an adjustment of $124.7 million to the previously recorded $380.2 million estimated goodwill impairment charge recorded during the three months ended March 31, 2016 (see Note 6 to our consolidated financial statements included in this Annual Report);
- a write-off of $5.2 million related to the value of an indefinite-lived trade name intangible asset in conjunction with finalizing our goodwill impairment analysis (see Note 7 to our consolidated financial statements included in this Annual Report);
- a loss of $22.7 million related to the termination of the development agreement, which included the carrying value of the development agreement asset that was written off (see Note 15 to our consolidated financial statements included in this Annual Report);
- an impairment charge of $1.7 million to write down a loan receivable in June 2016 (see Note 13 to our consolidated financial statements included in this Annual Report); and
- a loss of $9.5 million on the sales of certain assets, including the sale of Grassland (see Note 13 to our consolidated financial statements included in this Annual Report for a discussion of the sale of Grassland).

Revaluation of Liabilities. The revaluation of liabilities represents the change in the valuation of our contingent consideration liabilities related to royalty agreements acquired as part of certain business combinations during the year ended March 31, 2017. The increase in the expense during the year ended March 31, 2018 was due primarily to higher actual and expected production from new customers, resulting in an increase to the expected future royalty payment.

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Liquids

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

	Year Ended March 31,		
	2018	2017	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues (1)	$1,203,486	$807,172	$396,314
Cost of sales-excluding impact of derivatives	1,165,414	772,871	392,543
Cost of sales-derivative gain	(5,577)	(2,633)	(2,944)
Product margin	43,649	36,934	6,715
Butane sales:			
Revenues (1)	562,066	391,265	170,801
Cost of sales-excluding impact of derivatives	535,017	354,132	180,885
Cost of sales-derivative loss	19,616	7,863	11,753
Product margin	7,433	29,270	(21,837)
Other product sales:			
Revenues (1)	432,570	308,031	124,539
Cost of sales-excluding impact of derivatives	414,980	290,495	124,485
Cost of sales-derivative gain	(173)	(1,477)	1,304
Product margin	17,763	19,013	(1,250)
Other revenues:			
Revenues (1)	22,548	32,648	(10,100)
Cost of sales	3,930	12,893	(8,963)
Product margin	18,618	19,755	(1,137)
Expenses:			
Operating expenses	32,792	37,634	(4,842)
General and administrative expenses	5,331	4,831	500
Depreciation and amortization expense	24,937	19,163	5,774
Loss on disposal or impairment of assets, net	117,516	92	117,424
Total expenses	180,576	61,720	118,856
Segment operating (loss) income	$(93,113)	$43,252	$(136,365)
Liquids storage capacity - owned and leased (gallons) (2)	438,968	358,537	80,431
Propane sold (gallons)	1,361,173	1,267,076	94,097
Propane sold ($/gallon)	$0.884	$0.637	$0.247
Cost per propane sold ($/gallon)	$0.852	$0.608	$0.244
Propane product margin ($/gallon)	$0.032	$0.029	$0.003
Propane inventory (gallons) (2)	48,928	48,351	577
Propane storage capacity leased to third parties (gallons) (2)	29,662	33,495	(3,833)
Butane sold (gallons)	544,750	456,586	88,164
Butane sold ($/gallon)	$1.032	$0.857	$0.175

Cost per butane sold ($/gallon)	$1.018	$0.793	$0.225
Butane product margin ($/gallon)	$0.014	$0.064	$(0.050)
Butane inventory (gallons) (2)	15,385	9,438	5,947
Butane storage capacity leased to third parties (gallons) (2)	51,660	80,346	(28,686)
Other products sold (gallons)	400,405	343,365	57,040
Other products sold ($/gallon)	$1.080	$0.897	$0.183
Cost per other products sold ($/gallon)	$1.036	$0.842	$0.194
Other products product margin ($/gallon)	$0.044	$0.055	$(0.011)
Other products inventory (gallons) (2)	5,822	6,426	(604)

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(1) Revenues include $150.7 million and $100.0 million of intersegment sales during the years ended March 31, 2018 and 2017, respectively, that are eliminated in our consolidated statements of operations.
(2) Information is presented as of March 31, 2018 and March 31, 2017, respectively.

Propane Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due to higher commodity prices, and increased volume due to a new long-term marketing agreement.

Cost of Sales-Derivatives. Our cost of wholesale propane sales was reduced by $1.0 million and $1.5 million of net unrealized gains on derivatives for the years ended March 31, 2018 and 2017, respectively. Additionally, our cost of wholesale propane sales was reduced by $4.6 million and $1.1 million of net realized gains on derivatives for the years ended March 31, 2018 and 2017, respectively.

Product margins per gallon of propane sold were higher during the year ended March 31, 2018 than during the year ended March 31, 2017 facilitated by stronger winter demand.

Butane Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were primarily due to higher commodity prices.

Cost of Sales-Derivatives. Our cost of butane sales was increased by $0.5 million and $2.0 million of net unrealized losses on derivatives for the years ended March 31, 2018 and 2017, respectively. Additionally, our cost of butane sales was increased by $19.1 million and $5.9 million of net realized losses on derivatives for the years ended March 31, 2018 and 2017, respectively.

Product margins per gallon of butane sold were lower during the year ended March 31, 2018 than during the year ended March 31, 2017 due primarily to the overall competitive nature of the market as well as higher than anticipated unrecovered railcar fleet costs.

Other Products Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due primarily to a new long-term marketing agreement. Also, volumes have increased with the addition of the new Port Hudson terminal.

Cost of Sales-Derivatives. Our cost of sales of other products was reduced by $0.1 million and $0.2 million of net unrealized gains on derivatives for the years ended March 31, 2018 and 2017, respectively. Additionally, our cost of other products was reduced by $0.1 million and $1.3 million of net realized gains on derivatives for the years ended March 31, 2018 and 2017, respectively.

Product margin decrease during the year ended March 31, 2018 was due primarily to an increase in unrecovered railcar fleet costs.

Other Revenues. This revenue includes storage, terminaling and transportation services income. The decrease was due primarily to reduced transportation services and increased storage capacity available in the market.

Operating and General and Administrative Expenses. The decrease was due primarily to a reduction in incentive compensation that was paid in common units and reflected in “Corporate and Other”. Repair and maintenance expense was lower across most terminals due to tightly managing and prioritizing critical repairs.

Depreciation and Amortization Expense. The increase was due primarily to the acquisition of two liquids facilities during the previous fiscal year.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2018, we recorded a goodwill impairment charge of $116.9 million related to our salt dome storage facility in Utah due to the decreased demand for natural gas liquid storage and resulting decline in revenues and earnings as compared to actual and projected results of prior and future periods (see Note 6 to our consolidated financial statements included in this Annual Report). During the years ended March 31, 2018 and 2017, we recorded a net loss of $0.6 million and $0.1 million, respectively, related to the retirement of assets.

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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,		
	2018	2017	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues (1)	$403,871	$308,919	$94,952
Cost of sales	199,227	132,818	66,409
Product margin	204,644	176,101	28,543
Distillate sales:			
Revenues (1)	75,183	64,249	10,934
Cost of sales-excluding impact of derivatives	56,568	46,125	10,443
Cost of sales-derivative loss	276	378	(102)
Product margin	18,339	17,746	593
Other revenues:			
Revenues (1)	42,457	40,038	2,419
Cost of sales	13,296	12,268	1,028
Product margin	29,161	27,770	1,391
Expenses:			
Operating expenses	129,789	118,922	10,867
General and administrative expenses	11,322	10,761	561
Depreciation and amortization expense	43,692	42,966	726
Gain on disposal or impairment of assets, net	(88,209)	(287)	(87,922)
Total expenses	96,594	172,362	(75,768)
Segment operating income	$155,550	$49,255	$106,295
Propane sold (gallons)	204,145	177,599	26,546
Propane sold ($/gallon)	$1.978	$1.739	$0.239
Cost per propane sold ($/gallon)	$0.976	$0.748	$0.228
Propane product margin ($/gallon)	$1.002	$0.991	$0.011
Propane inventory (gallons) (2)	7,526	8,180	(654)
Distillates sold (gallons)	30,491	30,001	490
Distillates sold ($/gallon)	$2.466	$2.142	$0.324
Cost per distillates sold ($/gallon)	$1.864	$1.550	$0.314
Distillates product margin ($/gallon)	$0.602	$0.592	$0.010
Distillates inventory (gallons) (2)	1,051	1,148	(97)

(1) Revenues include $0.1 million and $0.1 million of intersegment sales during the years ended March 31, 2018 and 2017, respectively, that are eliminated in our consolidated statement of operations.
(2) Information is presented as of March 31, 2018 and March 31, 2017, respectively.

Revenues and Cost of Sales. The increases in propane revenues and costs of sales were due primarily to increased volumes as a result of higher demand related to colder winter weather and acquisitions made during the current and previous fiscal years, as well as an increase in commodity prices. Distillate revenues and cost of sales also increased due to the increase in commodity prices.

Operating and General and Administrative Expenses. The increase was due primarily to increased expenses associated with acquisitions of retail propane businesses.

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

Gain on Disposal or Impairment of Assets, Net. During the year ended March 31, 2018, we recorded a gain of $89.3 million on the sale of a portion of our Retail Propane segment (see Note 15 to our consolidated financial statements included in this Annual Report). During the years ended March 31, 2018 and 2017, we recorded a net loss of $1.1 million and a net gain of $0.3 million, respectively, related to the sale of surplus assets.

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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.

	Year Ended March 31,		
	2018	2017	Change
	(in thousands, except per barrel amounts)		
Refined products sales:			
Revenues (1)	$11,827,222	$8,884,976	$2,942,246
Cost of sales-excluding impact of derivatives	11,709,786	8,732,312	2,977,474
Cost of sales-derivative loss	77,055	43,358	33,697
Product margin	40,381	109,306	(68,925)
Renewables sales:			
Revenues	373,669	447,232	(73,563)
Cost of sales-excluding impact of derivatives	362,457	443,229	(80,772)
Cost of sales-derivative loss	1,467	1,291	176
Product margin	9,745	2,712	7,033
Service fee revenues	300	10,963	(10,663)
Expenses:			
Operating expenses	14,057	23,177	(9,120)
General and administrative expenses	8,433	9,821	(1,388)
Depreciation and amortization expense	1,294	1,562	(268)
Gain on disposal or impairment of assets, net	(30,098)	(134,125)	104,027
Total income, net	(6,314)	(99,565)	93,251
Segment operating income	$56,740	$222,546	$(165,806)
Gasoline sold (barrels)	108,427	91,004	17,423
Diesel sold (barrels)	56,020	49,817	6,203
Ethanol sold (barrels)	3,438	4,605	(1,167)
Biodiesel sold (barrels)	2,079	2,413	(334)
Refined products and renewables storage capacity - leased (barrels) (2)	9,911	9,419	492
Refined products and renewables storage capacity sub-leased to third parties (barrels) (2)	1,068	1,043	25
Gasoline inventory (barrels) (2)	3,367	2,993	374
Diesel inventory (barrels) (2)	1,419	1,464	(45)
Ethanol inventory (barrels) (2)	701	727	(26)
Biodiesel inventory (barrels) (2)	261	471	(210)
Refined products sold ($/barrel)	$71.921	$63.094	$8.827
Cost per refined products sold ($/barrel)	$71.676	$62.318	$9.358
Refined products product margin ($/barrel)	$0.245	$0.776	$(0.531)
Renewable products sold ($/barrel)	$67.730	$63.726	$4.004
Cost per renewable products sold ($/barrel)	$65.964	$63.340	$2.624
Renewable products product margin ($/barrel)	$1.766	$0.386	$1.380

(1)

Revenues include $0.3 million and $0.5 million of intersegment sales during the years ended March 31, 2018, and 2017, respectively, that are eliminated in our consolidated statements of operations.

(2) Information is presented as of March 31, 2018 and March 31, 2017, respectively.

Refined Products Revenues and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due to an increase in refined products prices and increased volumes. The increased volumes were due primarily to additional pipeline capacity rights purchased during the year ended March 31, 2017, an

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expansion of our refined products operations and the continued demand for motor fuels. The decrease in margin was due primarily to negative impact of the continued decline in gasoline line space values on the Colonial Pipeline, discretionary terminal volume profitability and line space sales during the year ended March 31, 2018, compared to the year ended March 31, 2017. The average value of line space was approximately negative $0.007 per gallon for the year ended March 31, 2018, compared to an average value of approximately $0.009 per gallon for the year ended March 31, 2017.

Refined Products Cost of Sales-Derivatives. The margins for both the years ended March 31, 2018 and 2017 were negatively impacted by losses of $77.1 million and $43.4 million, respectively, from our risk management activities. These losses were due primarily to increasing future prices.

Renewables Revenues and Cost of Sales-Excluding Impact of Derivatives. The decreases in revenues and cost of sales-excluding impact of derivatives were due primarily to decreased volumes from the loss of a marketing contract with an equity method investee in December 2017, partially offset by an increase in renewables prices. The margin was higher during the year ended March 31, 2018 due primarily to favorable biodiesel margins resulting from the biodiesel tax credit being reinstated in February 2018 for the 2017 calendar year.

Renewables Cost of Sales-Derivatives. The margins for both the years ended March 31, 2018 and 2017 were negatively impacted by losses of $1.5 million and $1.3 million, respectively, from our risk management activities. These losses were due primarily to the weakness in the price of renewable identification numbers and increasing future prices.

Service Fee Revenues, Operating Expenses, General and Administrative Expenses. The decreases were due primarily to the expiration of a transition services agreement in October 2016 related to the sale of the general partner interest in TLP in February 2016 whereby we were reimbursed for certain expenses incurred on behalf of a third party.

Depreciation and Amortization Expense. The decrease was due primarily to certain assets being fully depreciated during the year ended March 31, 2017.

Gain on Disposal or Impairment of Assets, Net. During the year ended March 31, 2018, we recorded $30.1 million of the deferred gain from the sale of the general partner interest in TLP in February 2016 (see Note 2 to our consolidated financial statements included in this Annual Report for a further discussion). In addition, we recorded a net loss of less than $0.1 million on the disposal of certain assets.

During the year ended March 31, 2017, we recorded:

- a $104.1 million gain from the sale of all of the TLP units we owned (see Note 2 to our consolidated financial statements included in this Annual Report for a further discussion);
- $30.1 million of the deferred gain from the sale of the general partner in interest in TLP in February 2016 (see Note 2 to our consolidated financial statements included in this Annual Report for a further discussion); and
- a loss of $0.1 million on the sales of certain assets.

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Corporate and Other

The operating loss within “Corporate and Other” includes the following components for the periods indicated:

	Year Ended March 31,		
	2018	2017	Change
	(in thousands)		
Other revenues:			
Revenues	$1,174	$844	$330
Cost of sales	530	400	130
Margin	644	444	200
Expenses:			
Operating expenses	1,292	1,192	100
General and administrative expenses	75,158	82,723	(7,565)
Depreciation and amortization expense	3,779	3,612	167
Loss (gain) on disposal or impairment of assets, net	8	(1)	9
Total expenses	80,237	87,526	(7,289)
Operating loss	$(79,593)	$(87,082)	$7,489

General and Administrative Expenses. The decrease for the year ended March 31, 2018 was due primarily to a decrease in equity-based compensation expense related to service awards. The expense related to service awards was $16.2 million for the year ended March 31, 2018, compared to $37.2 million for the year ended March 31, 2017. The increase in expense in the prior fiscal year was due to the cancellation of awards which accelerated the expense reporting. In addition, during the first quarter of the prior fiscal year, the expense for the service awards was accounted for under the liability method and due to an increase in our unit price during that period, we recorded an increase in equity-based compensation expense. Also, see Note 10 to our consolidated financial statements included in this Annual Report for a further discussion of our equity-based compensation. The decrease from equity-based compensation was partially offset by increases in legal expenses and workmen’s compensation.

Equity in Earnings of Unconsolidated Entities

The increase of $4.9 million during the year ended March 31, 2018 was due primarily to increased earnings related to our investment in Glass Mountain. On December 22, 2017, we sold our previously held 50% interest in Glass Mountain. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

Interest Expense

Interest expense includes interest charged on our revolving credit facilities, senior secured notes, and senior unsecured notes, as well as amortization of debt issuance costs, letter of credit fees, interest on equipment financing notes, and accretion of interest on non-interest bearing debt obligations. The increase of $49.1 million during the year ended March 31, 2018 was due primarily to the issuance of the 2023 Notes and 2025 Notes which have higher interest rates than our revolving credit facility. This was offset by lower interest expense on our revolving credit facility as our average balance outstanding decreased from $1.7 billion for the year ended March 31, 2017 to $1.0 billion for the year ended March 31, 2018.

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(Loss) Gain on Early Extinguishment of Liabilities, Net

The following table summarizes the components of (loss) gain on early extinguishment of liabilities, net for the periods indicated:

	Year Ended March 31,	
	2018	2017
	(in thousands)	
Early extinguishment of long-term debt (1)	$ (23,201)	$ 6,922
Release of contingent consideration liabilities (2)	—	22,278
Write-off deferred debt issuance costs (3)	—	(4,473)
(Loss) gain on early extinguishment of liabilities, net	$ (23,201)	$ 24,727

(1) During the year ended March 31, 2018, this relates to net losses (inclusive of debt issuance costs written off) on the early extinguishment of all of the senior secured notes and a portion of the 2019 Notes, 2023 Notes and 2025 Notes. During the year ended March 31, 2017, this relates to net gains (inclusive of debt issuance costs written off) on the early extinguishment of a portion of the 2019 Notes and 2021 Notes (as defined herein) and certain equipment loans. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion.

(2) Relates to the release of certain contingent consideration liabilities in conjunction with the termination of the development agreement in June 2016 (see Note 15 to our consolidated financial statements included in this Annual Report for a further discussion). Also, during the year ended March 31, 2017, we acquired certain parcels of land on which one of our water solutions facilities is located and recorded a gain on the release of certain contingent consideration liabilities as the royalty agreement was terminated.

(3) Relates to the write off of certain deferred debt issuance costs in connection with the amendment and restatement of our Credit Agreement (as defined herein) (see Note 7 to our consolidated financial statements included in this Annual Report for a further discussion).

Other Income, Net

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

	Year Ended March 31,	
	2018	2017
	(in thousands)	
Interest income (1)	$ 7,627	$ 8,605
Crude oil marketing arrangement (2)	(76)	(1,500)
Termination of storage sublease agreement (3)	—	16,205
Other (4)	852	4,452
Other income, net	$ 8,403	$ 27,762

(1) During the year ended March 31, 2018, this relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility to be utilized by a third party and to a loan receivable from Victory Propane, LLC (see Note 13 to our consolidated financial statements included in this Annual Report for a further discussion). During the year ended March 31, 2017, this relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility to be utilized by a third party and to loan receivables from Victory Propane, LLC and Grassland (see Note 13 to our consolidated financial statements included in this Annual Report for a further discussion). On June 3, 2016, we acquired the remaining 65% ownership interest in Grassland and all interest income on the receivable from Grassland has been eliminated in consolidation subsequent to that date.

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

(3) Represents a gain from the termination of a storage sublease agreement (see Note 15 to our consolidated financial statements included in this Annual Report for a further discussion).

(4) During the year ended March 31, 2018, this relates primarily to proceeds from a litigation settlement. During the year ended March 31, 2017, this relates primarily to a distribution from TLP pursuant to the agreement to sell all of the TLP common units we owned in April 2016, a gain on insurance settlement related to business interruption insurance coverage on a facility in our Water Solutions segment and a payment received related to a contract termination.

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Income Tax Expense

Income tax expense was $1.5 million during the year ended March 31, 2018, compared to income tax expense of $1.9 million during the year ended March 31, 2017. The decrease in income tax expense was due primarily to a lower state franchise tax liability in Texas as well as a lower Canadian tax liability from our taxable corporate subsidiaries in Canada. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

Noncontrolling Interests - Redeemable and Non-redeemable

Noncontrolling interests represent the portion of certain consolidated subsidiaries that are owned by third parties. The decrease of $5.6 million during the year ended March 31, 2018 was due primarily to adjustments related to noncontrolling interests during the year ended March 31, 2017.

Segment Operating Results for the Years Ended March 31, 2017 and 2016

Crude Oil Logistics

The following table summarizes the operating results of our Crude Oil Logistics segment for the periods indicated:

	Year Ended March 31,		
	2017	2016	Change
	(in thousands, except per barrel amounts)		
Revenues:			
Crude oil sales	$1,603,667	$3,170,891	$(1,567,224)
Crude oil transportation and other	70,027	55,882	14,145
Total revenues (1)	1,673,694	3,226,773	(1,553,079)
Expenses:			
Cost of sales-excluding impact of derivatives	1,573,246	3,133,097	(1,559,851)
Cost of sales-derivative loss (gain)	5,579	(11,686)	17,265
Operating expenses	41,535	43,458	(1,923)
General and administrative expenses	5,961	8,334	(2,373)
Depreciation and amortization expense	54,144	39,363	14,781
Loss on disposal or impairment of assets, net	10,704	54,952	(44,248)
Total expenses	1,691,169	3,267,518	(1,576,349)
Segment operating loss	$(17,475)	$(40,745)	$23,270
Crude oil sold (barrels)	34,212	67,211	(32,999)
Crude oil transported on owned pipelines (barrels)	6,365	—	6,365
Crude oil storage capacity - owned and leased (barrels) (2)	7,024	6,115	909
Crude oil storage capacity leased to third parties (barrels) (2)	3,717	3,127	590
Crude oil inventory (barrels) (2)	2,844	2,123	721
Crude oil sold ($/barrel)	$46.874	$47.178	$(0.304)
Cost per crude oil sold ($/barrel)	$46.148	$46.442	$(0.294)
Crude oil product margin ($/barrel)	$0.726	$0.736	$(0.010)

(1) Revenues include $6.8 million and $9.7 million of intersegment sales during the years ended March 31, 2017 and 2016, respectively, that are eliminated in our consolidated statements of operations.
(2) Information is presented as of March 31, 2017 and March 31, 2016, respectively.

Crude Oil Sales Revenues. The decrease in our sales volume was due primarily to increased competition. In addition, we also had an increase in buy/sell transactions during the year ended March 31, 2017, compared to the year ended March 31, 2016. These are transactions in which we transact to purchase product from a counterparty and sell the same volumes of product to the same counterparty at a different location or time. As the revenues and costs of sales are netted for these transaction, so are the volumes.

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Crude Oil Transportation and Other Revenues. The increase was due primarily to our Grand Mesa Pipeline becoming operational on November 1, 2016 with revenues of $29.2 million, partially offset by the flattening of the contango curve for crude oil (a condition in which forward crude oil prices are greater than spot prices) during the year ended March 31, 2017, compared to the year ended March 31, 2016, and lower revenues in our trucking and barge operations during the year ended March 31, 2017 due to a general slowdown in demand for transportation services, compared to the year ended March 31, 2016.

Cost of Sales-Excluding Impact of Derivatives. The decrease was due primarily to the decline in crude oil prices and volumes due to increased competition during the year ended March 31, 2017, compared to the year ended March 31, 2016.

Cost of Sales-Derivatives. Our cost of sales during the year ended March 31, 2017 was increased by $7.1 million of net realized losses on derivatives and reduced by $1.5 million of net unrealized gains on derivatives. Our cost of sales during the year ended March 31, 2016 was reduced by $13.8 million of net realized gains on derivatives and increased by $2.1 million of net unrealized losses on derivatives.

Operating and General and Administrative Expenses. The decrease was due primarily to lower compensation expense related to a reduction in the number of employees as a result of organizational changes, lower repair and maintenance expense related to trucking operations resulting from a general slowdown in demand for transportation services, and lower repair and maintenance expense related to having a newer fleet of barges and the timing of repairs, partially offset by our Grand Mesa Pipeline becoming operational on November 1, 2016 which incurred operating expenses of $4.8 million.

Depreciation and Amortization Expense. The increase was due primarily to our Grand Mesa Pipeline becoming operational on November 1, 2016, partially offset by certain intangible assets being fully amortized during the year ended March 31, 2016.

Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2017, we recorded a net loss of $6.5 million on the sales of certain assets and a loss of $4.2 million due to the write-down of certain other assets. During the year ended March 31, 2016, we recorded a loss of $50.1 million due to the write-down of certain assets, a loss of $3.1 million due to the cancellation of two previously-planned projects and a loss of $1.8 million on the sales of certain other assets.

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Water Solutions

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

	Year Ended March 31,		
	2017	2016	Change
	(in thousands, except per barrel and per day amounts)		
Revenues:			
Service fees	$110,049	$136,710	$(26,661)
Recovered hydrocarbons	31,103	41,090	(9,987)
Other revenues	18,449	7,201	11,248
Total revenues	159,601	185,001	(25,400)
Expenses:			
Cost of sales-excluding impact of derivatives	2,071	(241)	2,312
Cost of sales-derivative loss (gain)	1,997	(7,095)	9,092
Operating expenses	85,562	112,538	(26,976)
General and administrative expenses	2,469	2,778	(309)
Depreciation and amortization expense	101,758	91,685	10,073
(Gain) loss on disposal or impairment of assets, net	(85,560)	381,682	(467,242)
Revaluation of liabilities	6,717	(82,673)	89,390
Total expenses	115,014	498,674	(383,660)
Segment operating income (loss)	$44,587	$(313,673)	$358,260
Wastewater processed (barrels per day)			
Eagle Ford Basin	208,649	236,792	(28,143)
Permian Basin	184,702	179,413	5,289
DJ Basin	68,253	107,353	(39,100)
Other Basins	40,185	45,949	(5,764)
Total	501,789	569,507	(67,718)
Solids processed (barrels per day)	3,056	3,149	(93)
Skim oil sold (barrels per day)	1,989	2,935	(946)
Service fees for wastewater processed ($/barrel)	$0.60	$0.66	$(0.06)
Recovered hydrocarbons for wastewater processed ($/barrel)	$0.17	$0.20	$(0.03)
Operating expenses for wastewater processed ($/barrel)	$0.47	$0.54	$(0.07)

Service Fee Revenues. The decrease was due primarily to a decrease in the volume processed from a slowdown in customer production and development activity and a lower price per barrel received in current market conditions from new facilities being operational during the year ended March 31, 2017.

Recovered Hydrocarbon Revenues. The decrease was due primarily to a decrease in the volume of wastewater processed and a decrease in the amount of hydrocarbons per barrel of wastewater processed.

Other Revenues. The increase was due primarily to an increase in revenues in the freshwater and water pipeline businesses as well as revenue from trucking wastewater to certain of our water solutions facilities. See the below discussion of the loss on the sale of Grassland.

Cost of Sales-Excluding Impact of Derivatives. The increase was due to trucking expenses to bring wastewater to certain of our water solutions facilities.

Cost of Sales-Derivatives. We enter into derivatives in our Water Solutions segment to protect against the risk of a decline in the market price of the hydrocarbons we expect to recover when processing the wastewater and selling the skim oil. Our cost of sales during the year ended March 31, 2017 included $4.1 million of net realized losses on derivatives and the reversal of $2.1 million of net unrealized losses on derivatives at March 31, 2016 as there were no open derivatives at March 31, 2017. Our cost of sales during the year ended March 31, 2016 included $10.3 million of net realized gains on

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derivatives and $3.2 million of net unrealized losses on derivatives. In December 2015, we settled derivative contracts that had scheduled settlement dates from January 2016 through December 2016, in order to lock in the gains on those derivatives.

Operating and General and Administrative Expenses. The decrease was due primarily to lower costs of operations of water disposal wells due to lower volumes processed and cost reduction efforts.

Depreciation and Amortization Expense. The increase was due primarily to acquisitions and developed facilities, partially offset by lower amortization expense from the write-off of an intangible asset as well as certain intangible assets being fully amortized during the years ended March 31, 2017 and 2016 (see Note 7 to our consolidated financial statements included in this Annual Report).

(Gain) Loss on Disposal or Impairment of Assets, Net. During the year ended March 31, 2017, we recorded:

- an adjustment of $124.7 million to the previously recorded $380.2 million estimated goodwill impairment charge recorded during the three months ended March 31, 2016 (see Note 6 to our consolidated financial statements included in this Annual Report);
- a write-off of $5.2 million related to the value of an indefinite-lived trade name intangible asset in conjunction with finalizing our goodwill impairment analysis (see Note 7 to our consolidated financial statements included in this Annual Report);
- a loss of $22.7 million related to the termination of the development agreement, which included the carrying value of the development agreement asset that was written off (see Note 15 to our consolidated financial statements included in this Annual Report);
- an impairment charge of $1.7 million to write down a loan receivable in June 2016 (see Note 13 to our consolidated financial statements included in this Annual Report); and
- a loss of $9.5 million on the sales of certain assets, including the sale of Grassland (see Note 13 to our consolidated financial statements included in this Annual Report for a discussion of the sale of Grassland).

During the year ended March 31, 2016, we recorded:

- an estimated goodwill impairment charge of $380.2 million as the decline in crude oil prices and crude oil production have had an unfavorable impact on our Water Solutions business (see Note 6 to our consolidated financial statements included in this Annual Report); and
- a loss of $1.5 million on the sales of certain other assets.

Revaluation of Liabilities. The revaluation of liabilities represents the change in the valuation of our contingent consideration liabilities related to royalty agreements acquired as part of certain business combinations during the years ended March 31, 2017 and 2016. The increase in the expense during the year ended March 31, 2017 was due primarily to the reduction in the liability recorded during the year ended March 31, 2016 due to lower anticipated production and development activity due to lower commodity prices.

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Liquids

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

	Year Ended March 31,		
	2017	2016	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues (1)	$807,172	$618,919	$188,253
Cost of sales-excluding impact of derivatives	772,871	570,495	202,376
Cost of sales - derivative (gain) loss	(2,633)	1,239	(3,872)
Product margin	36,934	47,185	(10,251)
Butane sales:			
Revenues (1)	391,265	317,994	73,271
Cost of sales-excluding impact of derivatives	354,132	269,310	84,822
Cost of sales-derivative loss (gain)	7,863	(4,092)	11,955
Product margin	29,270	52,776	(23,506)
Other product sales:			
Revenues (1)	308,031	302,181	5,850
Cost of sales-excluding impact of derivatives	290,495	266,492	24,003
Cost of sales-derivative (gain) loss	(1,477)	426	(1,903)
Product margin	19,013	35,263	(16,250)
Other revenues:			
Revenues (1)	32,648	35,943	(3,295)
Cost of sales	12,893	13,806	(913)
Product margin	19,755	22,137	(2,382)
Expenses:			
Operating expenses	37,634	45,140	(7,506)
General and administrative expenses	4,831	8,806	(3,975)
Depreciation and amortization expense	19,163	15,642	3,521
Loss on disposal or impairment of assets, net	92	11,600	(11,508)
Total expenses	61,720	81,188	(19,468)
Segment operating income	$43,252	$76,173	$(32,921)
Liquids storage capacity - owned and leased (gallons) (2)	358,537	292,110	66,427
Propane sold (gallons)	1,267,076	1,244,529	22,547
Propane sold ($/gallon)	$0.637	$0.497	$0.140
Cost per propane sold ($/gallon)	$0.608	$0.459	$0.149
Propane product margin ($/gallon)	$0.029	$0.038	$(0.009)
Propane inventory (gallons) (2)	48,351	56,584	(8,233)
Propane storage capacity leased to third parties (gallons) (2)	33,495	33,264	231
Butane sold (gallons)	456,586	483,206	(26,620)
Butane sold ($/gallon)	$0.857	$0.658	$0.199

Cost per butane sold ($/gallon)	$0.793	$0.549	$0.244
Butane product margin ($/gallon)	$0.064	$0.109	$(0.045)
Butane inventory (gallons) (2)	9,438	14,629	(5,191)
Butane storage capacity leased to third parties (gallons) (2)	80,346	72,450	7,896
Other products sold (gallons)	343,365	360,716	(17,351)
Other products sold ($/gallon)	$0.897	$0.838	$0.059
Cost per other products sold ($/gallon)	$0.842	$0.740	$0.102
Other products product margin ($/gallon)	$0.055	$0.098	$(0.043)
Other products inventory (gallons) (2)	6,426	6,297	129

(1) Revenues include $100.0 million and $80.6 million of intersegment sales during the years ended March 31, 2017 and 2016, respectively, that are eliminated in our consolidated statements of operations.
(2) Information is presented as of March 31, 2017 and March 31, 2016, respectively.

Propane Sales. The increase in revenues was due to higher commodity prices, partially offset by warmer winter temperatures, as compared to the prior year, experienced by certain regions in which we operate.

Our cost of wholesale propane sales was reduced by $1.5 million and $2.1 million, respectively, of net unrealized gains on derivatives for the years ended March 31, 2017 and 2016. Additionally, our cost of wholesale propane sales was reduced by $1.1 million of net realized gains on derivatives and increased by $3.4 million of net realized losses on derivatives for the years ended March 31, 2017 and 2016, respectively.

Product margins per gallon of propane sold were lower during the year ended March 31, 2017 than during the year ended March 31, 2016. Propane prices declined significantly during February and March of 2017. Declining propane prices typically have an adverse effect on our margins as we were unable to fully recoup fixed storage fees and railcar lease costs.

Butane Sales. The increase in revenues and cost of sales was primarily a function of higher commodity prices.

Our cost of butane sales during the year ended March 31, 2017 was increased by $2.0 million of net unrealized losses on derivatives, as compared to a reduction of $1.9 million of net unrealized gains on derivatives during the year ended March 31, 2016. Additionally, our cost of butane sales was increased by $5.9 million of net realized losses on derivatives and reduced by $2.2 million of net realized gains on derivatives for the years ended March 31, 2017 and 2016, respectively.

Product margins per gallon of butane sold were lower during the year ended March 31, 2017 than during the year ended March 31, 2016 primarily due to underutilization of our leased railcar fleet.

Other Products Sales. The decrease in revenues was primarily due to lower volumes as a result of decreases in production related to a customer’s contract.

Our cost of sales of other products during the year ended March 31, 2017 was reduced by $0.2 million of net unrealized gains on derivatives, as compared to less than $0.1 million of net unrealized losses on derivatives during the year ended March 31, 2016. Additionally, our cost of other products was reduced by $1.3 million of net realized gains on derivatives and increased by $0.4 million of net realized losses on derivatives for the years ended March 31, 2017 and 2016, respectively.

Product margins during the year ended March 31, 2017 decreased primarily due to a decline in the margin on sales of asphalt, as commodity prices which correlate with crude oil prices have declined.

Other Revenues. This revenue includes storage, terminaling and transportation services income. Other revenues decreased due to the increased availability of transportation services and storage capacity in the market. While railcars costs have held steady, the value we are able to realize for the railcar in the market has dropped significantly year over year, resulting in lower revenues and volumes, however costs have remained consistent.

Operating and General and Administrative Expenses. The decrease was due primarily to a reduction in overall compensation expenses due to lower incentive compensation and commission expense as well as continued cost management monitoring which focuses on expense reductions.

Depreciation and Amortization Expense. The increase was due to expansion of existing terminals and acquisition of two new terminals.

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

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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,		
	2017	2016	Change
	(in thousands, except per gallon amounts)		
Propane sales:			
Revenues (1)	$308,919	$248,673	$60,246
Cost of sales	132,818	95,191	37,627
Product margin	176,101	153,482	22,619
Distillate sales:			
Revenues (1)	64,249	64,868	(619)
Cost of sales-excluding impact of derivatives	46,125	48,972	(2,847)
Cost of sales-derivative loss (gain)	378	(781)	1,159
Product margin	17,746	16,677	1,069
Other product sales:			
Revenues (1)	40,038	39,436	602
Cost of sales	12,268	13,375	(1,107)
Product margin	27,770	26,061	1,709
Expenses:			
Operating expenses	118,922	104,287	14,635
General and administrative expenses	10,761	11,982	(1,221)
Depreciation and amortization expense	42,966	35,992	6,974
Gain on disposal or impairment of assets, net	(287)	(137)	(150)
Total expenses	172,362	152,124	20,238
Segment operating income	$49,255	$44,096	$5,159
Propane sold (gallons)	177,599	152,238	25,361
Propane sold ($/gallon)	$1.739	$1.633	$0.106
Cost per propane sold ($/gallon)	$0.748	$0.625	$0.123
Propane product margin ($/gallon)	$0.991	$1.008	$(0.017)
Propane inventory (gallons) (2)	8,180	7,314	866
Distillates sold (gallons)	30,001	30,674	(673)
Distillates sold ($/gallon)	$2.142	$2.115	$0.027
Cost per distillates sold ($/gallon)	$1.550	$1.571	$(0.021)
Distillates product margin ($/gallon)	$0.592	$0.544	$0.048
Distillates inventory (gallons) (2)	1,148	1,223	(75)

(1) Revenues include $0.1 million of intersegment sales during the year ended March 31, 2017 that are eliminated in our consolidated statement of operations.
(2) Information is presented as of March 31, 2017 and March 31, 2016, respectively.

Revenues. The increase in propane revenues was primarily due to the four acquisitions in fiscal year 2017, partially offset by warmer winter temperatures, as compared to the prior year, experienced by certain regions in which we operate.

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Cost of Sales. The increase in propane cost of sales was due to the acquisitions in fiscal year 2017 as well as an increase in commodity prices. The decrease in distillates cost of sales was due to lower commodity prices in the first and second quarter of fiscal year 2017.

Operating and General and Administrative Expenses. The increase was due primarily to increased expenses associated with acquisitions of retail propane businesses.

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

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Refined Products and Renewables

The following table summarizes the operating results of our Refined Products and Renewables segment for the periods indicated. As previously reported, on February 1, 2016, we sold our general partner interest in TLP. As a result, on February 1, 2016, we deconsolidated TLP and began to account for our limited partner investment in TLP using the equity method of accounting. Also, on April 1, 2016, we sold all of the TLP common units we owned.

	Year Ended March 31,		
	2017	2016	Change
	(in thousands, except per barrel amounts)		
Refined products sales:			
Revenues (1)	$8,884,976	$6,294,008	$2,590,968
Cost of sales-excluding impact of derivatives	8,732,312	6,240,026	2,492,286
Cost of sales-derivative loss (gain)	43,358	(78,783)	122,141
Product margin	109,306	132,765	(23,459)
Renewables sales:			
Revenues	447,232	390,753	56,479
Cost of sales-excluding impact of derivatives	443,229	382,663	60,566
Cost of sales-derivative loss (gain)	1,291	(2,451)	3,742
Product margin	2,712	10,541	(7,829)
Service fee revenues	10,963	108,221	(97,258)
Expenses:			
Operating expenses	23,177	95,371	(72,194)
General and administrative expenses	9,821	15,675	(5,854)
Depreciation and amortization expense	1,562	40,861	(39,299)
Gain on disposal or impairment of assets, net	(134,125)	(127,331)	(6,794)
Total (income) expense, net	(99,565)	24,576	(124,141)
Segment operating income	$222,546	$226,951	$(4,405)
Gasoline sold (barrels)	91,004	58,650	32,354
Diesel sold (barrels)	49,817	40,338	9,479
Ethanol sold (barrels)	4,605	4,199	406
Biodiesel sold (barrels)	2,413	1,595	818
Refined products and renewables storage capacity - leased (barrels) (2)	9,419	7,188	2,231
Refined products and renewables storage capacity sub-leased to third parties (barrels) (2)	1,043	713	330
Gasoline inventory (barrels) (2)	2,993	1,602	1,391
Diesel inventory (barrels) (2)	1,464	2,059	(595)
Ethanol inventory (barrels) (2)	727	766	(39)
Biodiesel inventory (barrels) (2)	471	350	121
Refined products sold ($/barrel)	$63.094	$63.584	$(0.490)
Cost per refined products sold ($/barrel)	$62.318	$62.242	$0.076
Refined products product margin ($/barrel)	$0.776	$1.342	$(0.566)
Renewable products sold ($/barrel)	$63.726	$67.441	$(3.715)
Cost per renewable products sold ($/barrel)	$63.340	$65.622	$(2.282)
Renewable products product margin ($/barrel)	$0.386	$1.819	$(1.433)

(1) Revenues include $0.5 million and $0.9 million of intersegment sales during the years ended March 31, 2017 and 2016, respectively, that are eliminated in our consolidated statements of operations.
(2) Information is presented as of March 31, 2017 and March 31, 2016, respectively.

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Refined Products Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due primarily to increased volumes from additional pipeline capacity rights purchased during the years ended March 31, 2017 and 2016, an expansion of our refined products operations, and the continued demand for motor fuels in the current low gasoline price environment. These increases were partially offset by a decrease in refined products sale prices during the year ended March 31, 2017 as well as storage fees paid to TLP no longer being eliminated as TLP was deconsolidated on February 1, 2016.

Refined Products Cost of Sales-Derivatives. The margin for the year ended March 31, 2017 was negatively impacted by a loss of $43.4 million from our risk management activities due primarily to increasing future prices. The margin for the year ended March 31, 2016 was positively impacted by a gain of $78.8 million from our risk management activities due primarily to decreasing future prices.

Renewables Sales and Cost of Sales-Excluding Impact of Derivatives. The increases in revenues and cost of sales-excluding impact of derivatives were due primarily to increased volumes from being able to liquidate storage volumes as the renewables markets shifted from being in contango (a condition in which forward renewables prices are greater than spot prices) to being backwardated (a condition in which forward renewables prices are lower than spot prices) during the year ended March 31, 2017. These increases were partially offset by a decrease in renewables sale prices and a decrease in the cost of renewables purchased during the year ended March 31, 2017. Margins for biodiesel are impacted by a biodiesel tax credit. When the tax credit is passed at the end of the calendar year and retroactive for the entire calendar year, it allows for more optionality and trading in the market and allows us to enter into deals that could provide for a positive upside if that credit is passed. Product margins were lower during the year ended March 31, 2017, compared to the year ended March 31, 2016 as a result of the biodiesel tax credit being in place for the entire 2016 calendar year, compared to being reinstated in December 2015 for the 2015 calendar year.

Renewables Cost of Sales-Derivatives. The margin for the year ended March 31, 2017 was negatively impacted by a loss of $1.3 million from our risk management activities due primarily to the weakness in the price of renewable identification numbers and increasing future prices. The margin for the year ended March 31, 2016 was positively impacted by a gain of $2.5 million from our risk management activities due primarily to decreasing future prices.

Service Fee Revenues, Operating Expenses, General and Administrative Expenses, Depreciation and Amortization Expense. The decreases were due primarily to the inclusion of TLP for ten months of the year ended March 31, 2016 with no comparable activity during the year ended March 31, 2017, as TLP was deconsolidated on February 1, 2016.

Gain on Disposal or Impairment of Assets, Net. During the year ended March 31, 2017, we recorded:

- a $104.1 million gain from the sale of all of the TLP units we owned (see Note 2 to our consolidated financial statements included in this Annual Report for a further discussion);
- $30.1 million of the deferred gain from the sale of the general partner in interest in TLP in February 2016 (see Note 2 to our consolidated financial statements included in this Annual Report for a further discussion); and
- a loss of $0.1 million on the sales of certain assets.

During the year ended March 31, 2016, we recorded:

- a gain on disposal of our general partner interest in TLP of $329.9 million, of which $204.6 million was deferred and $5.0 million of the deferred gain was recorded during the year ended March 31, 2016 (see Note 2 to our consolidated financial statements included in this Annual Report for a further discussion);
- a loss of $1.8 million related to certain property, plant and equipment that we have retired; and
- a loss of $1.3 million related to the sale of certain tank bottoms.

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Corporate and Other

The operating loss within “Corporate and Other” includes the following components for the periods indicated:

	Year Ended March 31,		
	2017	2016	Change
	(in thousands)		
Other revenues:			
Revenues	$844	$462	$382
Cost of sales	400	182	218
Margin	444	280	164
Expenses:			
Operating expenses	1,192	338	854
General and administrative expenses	82,723	91,966	(9,243)
Depreciation and amortization expense	3,612	5,381	(1,769)
Gain on disposal or impairment of assets, net	(1)	—	(1)
Total expenses	87,526	97,685	(10,159)
Operating loss	$(87,082)	$(97,405)	$10,323

General and Administrative Expenses. The decrease was due primarily to lower equity-based compensation expense. We recorded expense of $7.2 million for the year ended March 31, 2017, compared to $16.4 million for the year ended March 31, 2016. The year ended March 31, 2016 included the initial grant of the performance units as well as the vesting of the first tranche. The expense associated with the service award units (exclusive of accruals of annual bonuses paid or expected to be paid in common units) was $37.2 million during the year ended March 31, 2017, compared to $35.2 million during the year ended March 31, 2016. The increase was due primarily to a change in our process for the withholding of taxes on vesting which no longer requires us to revalue our unvested units each period. During the year ended March 31, 2016, the value of the unvested units was reduced due to declines in our unit price and resulted in the reversal of previously recorded compensation expense. See Note 10 to our consolidated financial statements included in this Annual Report for a further discussion.

Equity in Earnings of Unconsolidated Entities

The decrease of $13.0 million during the year ended March 31, 2017 was due primarily to a decrease of $12.6 million as a result of deconsolidating TLP on February 1, 2016 and selling all of the TLP common units we owned on April 1, 2016 (see Note 2 to our consolidated financial statements included in this Annual Report).

Revaluation of Investments

On June 3, 2016, we acquired the remaining 65% ownership interest in Grassland. Prior to the completion of this transaction, we accounted for our previously held 35% ownership interest in Grassland using the equity method of accounting. As we owned a controlling interest in Grassland, we revalued our previously held 35% ownership interest to fair value of $0.8 million and recorded a loss of $14.9 million. As the amount paid (cash plus the fair value of our previously held ownership interest) was less than the fair value of the assets acquired and liabilities assumed, we recorded a bargain purchase gain of $0.6 million (see Note 13 to our consolidated financial statements included in this Annual Report).

Interest Expense

The increase of $17.4 million during the year ended March 31, 2017 was due primarily to the issuance of the 2023 Notes and 2025 Notes which have higher interest rates than our revolving credit facility, partially offset by lower interest expense related to TLP's credit facility (our interest in TLP was acquired in July 2014, and we deconsolidated TLP as of February 1, 2016) and lower interest expense as we repurchased a portion of the 2019 Notes and 2021 Notes during the years ended March 31, 2017 and 2016.

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Gain on Early Extinguishment of Liabilities, Net

The following table summarizes the components of gain on early extinguishment of liabilities, net for the periods indicated:

	Year Ended March 31,	
	2017	2016
	(in thousands)	
Release of contingent consideration liabilities (1)	$ 22,278	$ —
Early extinguishment of long-term debt (2)	6,922	28,532
Write-off deferred debt issuance costs (3)	(4,473)	—
Gain on early extinguishment of liabilities, net	$ 24,727	$ 28,532

(1) Relates to the release of certain contingent consideration liabilities in conjunction with the termination of the development agreement in June 2016 (see Note 15 to our consolidated financial statements included in this Annual Report for a further discussion). Also, during the year ended March 31, 2017, we acquired certain parcels of land on which one of our water solutions facilities is located and recorded a gain on the release of certain contingent consideration liabilities as the royalty agreement was terminated.

(2) Relates to net gains (inclusive of debt issuance costs written off) on the early extinguishment of a portion of the 2019 Notes and 2021 Notes and certain equipment loans (see Note 8 to our consolidated financial statements included in this Annual Report for a further discussion).

(3) Relates to the write off of certain deferred debt issuance costs in connection with the amendment and restatement of our Credit Agreement (as defined herein) (see Note 7 to our consolidated financial statements included in this Annual Report for a further discussion).

Other Income, Net

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

	Year Ended March 31,	
	2017	2016
	(in thousands)	
Interest income (1)	$ 8,605	$ 12,004
Crude oil marketing arrangement (2)	(1,500)	(6,726)
Termination of storage sublease agreement (3)	16,205	—
Other (4)	4,452	297
Other income, net	$ 27,762	$ 5,575

(1) Relates primarily to a loan receivable associated with our financing of the construction of a natural gas liquids facility to be utilized by a third party and to loan receivables from Victory Propane, LLC and Grassland (see Note 13 to our consolidated financial statements included in this Annual Report for a further discussion). On June 3, 2016, we acquired the remaining 65% ownership interest in Grassland and all interest income on the receivable from Grassland has been eliminated in consolidation subsequent to that date.

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

(3) Represents a gain from the termination of a storage sublease agreement (see Note 15 to our consolidated financial statements included in this Annual Report for a further discussion).

(4) During the year ended March 31, 2017, this relates primarily to a distribution from TLP pursuant to the agreement to sell all of the TLP common units we owned in April 2016, a gain on insurance settlement related to business interruption insurance coverage on a facility in our Water Solutions segment and a payment received related to a contract termination.

Income Tax Expense (Benefit)

Income tax expense was $1.9 million during the year ended March 31, 2017, compared to an income tax benefit of $0.4 million during the year ended March 31, 2016. Income tax benefit during the year ended March 31, 2016 included a benefit of $3.6 million related to a change in estimate of the income tax obligation payable related to TransMontaigne Inc. See Note 2 to our consolidated financial statements included in this Annual Report for a further discussion.

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Noncontrolling Interests - Redeemable and Non-redeemable

The decrease of $5.0 million during the year ended March 31, 2017 was due primarily to the deconsolidation of TLP on February 1, 2016 as a result of the sale of our general partner interest in TLP, partially offset by adjustments related to noncontrolling interests.

Non-GAAP Financial Measures

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

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

Other than for our Refined Products and Renewables segment, for purposes of our Adjusted EBITDA calculation, we make a distinction between realized and unrealized gains and losses on derivatives. During the period when a derivative contract is open, we record changes in the fair value of the derivative as an unrealized gain or loss. When a derivative contract matures or is settled, we reverse the previously recorded unrealized gain or loss and record a realized gain or loss. We do not draw such a distinction between realized and unrealized gains and losses on derivatives of our Refined Products and Renewables segment. The primary hedging strategy of our Refined Products and Renewables segment is to hedge against the risk of declines in the value of inventory over the course of the contract cycle, and many of the hedges are six months to one year in duration at inception. The "inventory valuation adjustment" row in the reconciliation table reflects the difference between the market value of the inventory of our Refined Products and Renewables segment at the balance sheet date and its cost. We include this in Adjusted EBITDA because the unrealized gains and losses associated with derivative contracts associated with the inventory of this segment, which are intended primarily to hedge inventory holding risk and are included in net income, also affect Adjusted EBITDA.

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

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
Net (loss) income	$(69,605)	$143,874	$(187,097)
Less: Net income attributable to noncontrolling interests	(240)	(6,832)	(11,832)
Less: Net income attributable to redeemable noncontrolling interests	(1,030)	—	—
Net (loss) income attributable to NGL Energy Partners LP	(70,875)	137,042	(198,929)
Interest expense	199,747	150,504	126,514
Income tax expense (benefit)	1,458	1,939	(420)
Depreciation and amortization	266,525	238,583	217,893
EBITDA	396,855	528,068	145,058
Net unrealized losses (gains) on derivatives	15,883	(3,338)	1,255
Inventory valuation adjustment (1)	11,033	7,368	24,390
Lower of cost or market adjustments	399	(1,283)	(5,932)
(Gain) loss on disposal or impairment of assets, net	(105,313)	(209,213)	320,783
Loss (gain) on early extinguishment of liabilities, net	23,201	(24,727)	(28,532)
Revaluation of investments	—	14,365	—
Equity-based compensation expense (2)	35,241	53,102	58,816
Acquisition expense (3)	263	1,771	2,002
Revaluation of liabilities (4)	20,607	12,761	(90,700)
Other (5)	10,081	2,443	(2,645)
Adjusted EBITDA	$408,250	$381,317	$424,495

(1) Amount reflects the difference between the market value of the inventory of our Refined Products and Renewables segment at the balance sheet date and its cost. See “Non-GAAP Financial Measures” section above for a further discussion.

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

(3) Amounts represent expenses we incurred related to legal and advisory costs associated with acquisitions, partially offset by reimbursement for certain legal costs incurred in prior periods.

(4) Amounts represent the non-cash valuation adjustment of contingent consideration liabilities, offset by the cash payments, related to royalty agreements acquired as part of acquisitions in our Water Solutions segment.

(5) The amount for the year ended March 31, 2018 represents non-cash operating expenses related to our Grand Mesa Pipeline, an adjustment to inventory related to prior periods and accretion expense for asset retirement obligations. The amount for the year ended March 31, 2017 represents non-cash operating expenses related to our Grand Mesa Pipeline and accretion expense for asset retirement obligations. The amount for the year ended March 31, 2016 represents adjustments for noncontrolling interests and accretion expense for asset retirement obligations.

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

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
Reconciliation to consolidated statements of operations:			
Depreciation and amortization per EBITDA table	$266,525	$238,583	$217,893
Intangible asset amortization recorded to cost of sales	(6,099)	(6,828)	(6,700)
Depreciation and amortization of unconsolidated entities	(9,044)	(12,136)	(14,814)
Depreciation and amortization attributable to noncontrolling interests	1,330	3,586	32,545
Depreciation and amortization per consolidated statements of operations	$252,712	$223,205	$228,924
Reconciliation to consolidated statements of cash flows:			
Depreciation and amortization per EBITDA table	$266,525	$238,583	$217,893
Amortization of debt issuance costs recorded to interest expense	10,619	7,762	13,587
Depreciation and amortization of unconsolidated entities	(9,044)	(12,136)	(14,814)
Depreciation and amortization attributable to noncontrolling interests	1,330	3,586	32,545
Depreciation and amortization per consolidated statements of cash flows	$269,430	$237,795	$249,211

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

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
Interest expense per EBITDA table	$199,747	$150,504	$126,514
Interest expense attributable to noncontrolling interests (1)	33	26	5,315
Interest expense attributable to unconsolidated entities (2)	(210)	(52)	567
Gain on extinguishment of debt of unconsolidated entities	—	—	693
Interest expense per consolidated statements of operations	$199,570	$150,478	$133,089

(1) Includes ten months of consolidated TLP interest expense during the year ended March 31, 2016.

(2) Includes two months of TLP interest expense as an equity method investment during the year ended March 31, 2016.

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The following tables reconcile operating income (loss) to Adjusted EBITDA by segment for the periods indicated. We have revised certain prior period information to be consistent with the calculation method used in the current fiscal year.

	Year Ended March 31, 2018						
	Crude Oil Logistics	Water Solutions	Liquids	Retail Propane	Refined Products and Renewables	Corporate and Other	Consolidated
	(in thousands)						
Operating income (loss)	$122,904	$(24,231)	$(93,113)	$155,550	$56,740	$(79,593)	$138,257
Depreciation and amortization	80,387	98,623	24,937	43,692	1,294	3,779	252,712
Amortization recorded to cost of sales	338	—	282	—	5,479	—	6,099
Net unrealized losses (gains) on derivatives	2,766	13,694	(577)	—	—	—	15,883
Inventory valuation adjustment	—	—	—	—	11,033	—	11,033
Lower of cost or market adjustments	—	—	504	—	(105)	—	399
(Gain) loss on disposal or impairment of assets, net	(111,393)	6,863	117,516	(88,209)	(30,098)	8	(105,313)
Equity-based compensation expense	—	—	—	—	—	35,241	35,241
Acquisition expense	—	—	—	—	—	263	263
Other income, net	535	211	105	555	604	6,393	8,403
Adjusted EBITDA attributable to unconsolidated entities	11,507	579	—	822	4,308	—	17,216
Adjusted EBITDA attributable to noncontrolling interest	—	(737)	—	(1,894)	—	—	(2,631)
Revaluation of liabilities	—	20,607	—	—	—	—	20,607
Other	10,617	461	85	(1,082)	—	—	10,081
Adjusted EBITDA	$117,661	$116,070	$49,739	$109,434	$49,255	$(33,909)	$408,250

	Year Ended March 31, 2017						
	Crude Oil Logistics	Water Solutions	Liquids	Retail Propane	Refined Products and Renewables	Corporate and Other	Consolidated
	(in thousands)						
Operating (loss) income	$(17,475)	$44,587	$43,252	$49,255	$222,546	$(87,082)	$255,083
Depreciation and amortization	54,144	101,758	19,163	42,966	1,562	3,612	223,205
Amortization recorded to cost of sales	384	—	781	—	5,663	—	6,828
Net unrealized (gains) losses on derivatives	(1,513)	(2,088)	216	47	—	—	(3,338)
Inventory valuation adjustment	—	—	—	—	7,368	—	7,368
Lower of cost or market adjustments	—	—	—	—	(1,283)	—	(1,283)
Loss (gain) on disposal or impairment of assets, net	10,704	(85,560)	92	(287)	(134,125)	(1)	(209,177)
Equity-based compensation expense	—	—	—	—	—	53,102	53,102
Acquisition expense	—	—	—	—	—	1,771	1,771
Other (expense) income, net	(412)	739	73	504	19,263	7,595	27,762

Adjusted EBITDA attributable to unconsolidated entities	11,589	106	—	(427)	3,975	—	15,243
Adjusted EBITDA attributable to noncontrolling interest	—	(9,210)	—	(1,241)	—	—	(10,451)
Revaluation of liabilities	—	12,761	—	—	—	—	12,761
Other	1,996	368	79	—	—	—	2,443
Adjusted EBITDA	$59,417	$63,461	$63,656	$90,817	$124,969	$(21,003)	$381,317

	Year Ended March 31, 2016						
	Crude Oil Logistics	Water Solutions	Liquids	Retail Propane	Refined Products and Renewables	Corporate and Other	Consolidated
	(in thousands)						
Operating (loss) income	$(40,745)	$(313,673)	$76,173	$44,096	$226,951	$(97,405)	$(104,603)
Depreciation and amortization	39,363	91,685	15,642	35,992	40,861	5,381	228,924
Amortization recorded to cost of sales	250	—	1,044	—	5,406	—	6,700
Net unrealized losses (gains) on derivatives	2,123	3,196	(4,008)	(56)	—	—	1,255
Inventory valuation adjustment	—	—	—	—	24,390	—	24,390
Lower of cost or market adjustments	(1,211)	—	—	—	(4,721)	—	(5,932)
Loss (gain) on disposal or impairment of assets, net	54,952	381,682	11,600	(137)	(127,331)	—	320,766
Equity-based compensation expense	—	—	—	—	877	58,315	59,192
Acquisition expense	—	—	—	7	—	1,995	2,002
Other (expense) income, net	(6,725)	2,144	281	791	443	8,641	5,575
Adjusted EBITDA attributable to unconsolidated entities	13,474	(701)	—	(425)	17,960	—	30,308
Adjusted EBITDA attributable to noncontrolling interest	—	(2,259)	—	(1,065)	(50,438)	—	(53,762)
Revaluation of liabilities	—	(90,700)	—	—	—	—	(90,700)
Other	11	329	40	—	—	—	380
Adjusted EBITDA	$61,492	$71,703	$100,772	$79,203	$134,398	$(23,073)	$424,495

Liquidity, Sources of Capital and Capital Resource Activities

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

Our borrowing needs vary during the year due in part to the seasonal nature of our Liquids, Retail Propane and Refined Products and Renewables businesses. 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 as well as building our gasoline inventory in anticipation of the winter gasoline contango and blending 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 and gasoline inventories need to be minimized due to certain inventory requirements.

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

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

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Under current market conditions, we are much less likely to pursue acquisitions than we have been in the past. We continue to undertake certain capital expansion projects and expect to be able to finance these projects through available capacity on our Revolving Credit Facility, asset sales or other forms of financing.

Other sources of liquidity during the year ended March 31, 2018 are discussed below.

Dispositions

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC LPG for net proceeds of $212.4 million in cash at closing.

On March 30, 2018, we completed the transaction to form a joint venture related to Sawtooth and received consideration consisting of a cash payment of approximately $37.6 million (excluding working capital) and the contribution of certain refined products rights and adjacent leasehold. The noncontrolling interest owner has an option to purchase our interest in Sawtooth within the next three years. See Note 15 to our consolidated financial statements included in this Annual report for a further discussion of this transaction.

On December 22, 2017, we sold our previously held 50% interest in Glass Mountain for net proceeds of $292.1 million.

Class B Preferred Units

During the year ended March 31, 2018, we issued 8,400,000 of our 9.00% Class B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (“Class B Preferred Units”) representing limited partner interests at a price of $25.00 per unit for net proceeds of $202.7 million (net of the underwriters’ discount of $6.6 million and offering costs of $0.7 million). See Note 10 to our consolidated financial statements included in this Annual Report for a further description of the Class B Preferred Units.

Long-Term Debt

Credit Agreement

We are party to a $1.765 billion credit agreement (the “Credit Agreement”) with a syndicate of banks, which was amended and restated in February 2017. As of March 31, 2018, 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”). Our Revolving Credit Facility includes an “accordion” feature that allows us to increase the capacity by $300 million if new lenders wish to join the syndicate or if current lenders wish to increase their commitments. The commitments under the Credit Agreement expire on October 5, 2021.

At March 31, 2018, we were in compliance with the covenants under the Credit Agreement.

Senior Secured Notes

On December 29, 2017, we repurchased all of the remaining outstanding senior secured notes for $250.2 million. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion of the repurchases. Prior to the December 29, 2017 repurchase of all the remaining outstanding senior secured notes, we made a semi-annual principal installment payment of $19.5 million on December 19, 2017.

Senior Unsecured Notes

The Senior Unsecured Notes include, as defined below, the 2019 Notes, 2021 Notes, 2023 Notes, and the 2025 Notes (collectively, the “Senior Unsecured Notes”).

Issuances

On July 9, 2014, we issued $400.0 million of 5.125% Senior Notes Due 2019 (the “2019 Notes”). The 2019 Notes mature on July 15, 2019. Interest is payable on January 15 and July 15 of each year.

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On October 16, 2013, we issued $450.0 million of 6.875% Senior Notes Due 2021 (the “2021 Notes”). The 2021 Notes mature on October 15, 2021. Interest is payable on April 15 and October 15 of each year.

On October 24, 2016, we issued $700.0 million of 7.50% Senior Notes Due 2023 (the “2023 Notes”). The 2023 Notes mature on November 1, 2023. Interest is payable on May 1 and November 1 of each year.

On February 22, 2017, we issued $500.0 million of 6.125% Senior Notes Due 2025 (the “2025 Notes”). The 2025 Notes mature on March 1, 2025. Interest is payable on March 1 and September 1 of each year.

Repurchases

During the year ended March 31, 2018, we repurchased $26.0 million of the 2019 Notes, $84.1 million of the 2023 Notes and $110.9 million of the 2025 Notes. See Note 8 to our consolidated financial statements included in this Annual Report for a further discussion of the repurchases and a detail of repurchases made in fiscal years 2017 and 2016.

Compliance

At March 31, 2018, we were in compliance with the covenants under all of the Senior Unsecured Notes indentures.

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

Revolving Credit Balances

The following table summarizes our Revolving Credit Facility borrowings for the periods indicated:

	Average Balance Outstanding	Lowest Balance	Highest Balance
	(in thousands)		
Year Ended March 31, 2018			
Expansion capital borrowings	$167,900	$—	$397,000
Working capital borrowings	$837,651	$719,500	$1,014,500
Year Ended March 31, 2017			
Expansion capital borrowings	$970,678	$—	$1,359,000
Working capital borrowings	$686,456	$465,500	$875,500

At-The-Market Program

On August 24, 2016, we entered into an equity distribution agreement in connection with an at-the-market program (the “ATM Program”) pursuant to which we may issue and sell up to $200.0 million of common units. We are under no obligation to issue equity under the ATM Program. We did not issue any common units under the ATM Program during the year ended March 31, 2018, and approximately $134.7 million remained available for sale under the ATM Program at March 31, 2018.

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Capital Expenditures, Acquisitions and Other Investments

The following table summarizes expansion and maintenance capital expenditures (which excludes additions for tank bottoms and line fill and has been prepared on the accrual basis), acquisitions and other investments for the periods indicated.

Year Ended March 31,	Capital Expenditures Expansion (1)	Maintenance (2)	Acquisitions	Other Investments (3)
	(in thousands)			
2018	$155,213	$ 37,713	$ 50,417	$ 27,889
2017	$334,383	$ 26,073	$ 122,832	$ 44,864
2016	$613,792	$ 42,001	$ 234,652	$ 11,431

(1) Includes the intangible assets received as consideration as part of the Sawtooth joint venture transaction (see Note 15 to our consolidated financial statements included in this Annual Report) during the year ended March 31, 2018. Includes expansion capital expenditures for TLP of $13.6 million during the year ended March 31, 2016.

(2) Includes maintenance capital expenditures for TLP of $11.6 million during year ended March 31, 2016.

(3) Amounts for the years ended March 31, 2018 and 2016 primarily related to contributions made to unconsolidated entities. Amounts for the year ended March 31, 2017 primarily related to payments made to terminate a development agreement and other liabilities.

We currently expect to spend approximately $250 million to $275 million on growth capital expenditures during fiscal year 2019, which includes certain acquisitions in our Water Solutions segment that we expect to close in the first quarter of our fiscal year 2019.

Cash Flows

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

Cash Flows Provided by (Used in):	Year Ended March 31, 2018	2017	2016
	(in thousands)		
Operating activities, before changes in operating assets and liabilities	$290,396	$258,573	$221,074
Changes in operating assets and liabilities	(152,754)	(282,813)	130,421
Operating activities	$137,642	$(24,240)	$351,495
Investing activities	$270,582	$(363,126)	$(445,327)
Financing activities	$(394,281)	$371,454	$80,705

Operating Activities. The seasonality of our natural gas liquids businesses has a significant effect on our cash flows from operating activities. Increases in natural gas liquids prices typically reduce our operating cash flows due to higher cash requirements to fund increases in inventories, and decreases in natural gas liquids prices typically increase our operating cash flows due to lower cash requirements to fund increases in inventories. In our Liquids and Retail Propane businesses, we typically experience operating losses or lower operating income during our first and second quarters, or the six months ending September 30, as a result of lower volumes of natural gas liquids sales and when we are building our inventory levels for the upcoming heating season. The heating season runs through the six months ending March 31. The seasonal motor fuel blend during the third quarter of our fiscal year impacts the value of our gasoline inventory in our Refined Products and Renewables business and also represents a period when we build inventory into our system. We borrow under our Revolving Credit Facility to supplement our operating cash flows during the periods in which we are building inventory. Our operations, and as a result our cash flows, are also impacted by positive and negative movements in commodity prices, which cause fluctuations in the value of inventory, accounts receivable and payables, due to increases and decreases in revenues and cost of sales. The change in net cash from operating activities between the years ended March 31, 2016, 2017 and 2018 was due primarily to higher inventory as a result of the purchase of additional pipeline capacity allocations in our Refined Products and Renewables segment during the year ended March 31, 2017.

Investing Activities. Net cash provided by investing activities was $270.6 million during the year ended March 31, 2018, compared to net cash used in investing activities of $363.1 million during the year ended March 31, 2017. The increase in net cash provided by investing activities was due primarily to:

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- a $418.1 million increase in proceeds from sales of assets due primarily to the sales of our previously held 50% interest in Glass Mountain, a portion of our Retail Propane segment and a portion of Sawtooth and an increase in proceeds from the sale of excess pipe in our Crude Oil Logistics segment during the year ended March 31, 2018 and the sales of TLP common units we owned and Grassland during the year ended March 31, 2017;
- a decrease in capital expenditures from $363.9 million during the year ended March 31, 2017 to $156.2 million during the year ended March 31, 2018 due primarily to capital expenditures for the Grand Mesa Pipeline and the purchase of additional pipeline capacity allocations during the year ended March 31, 2017;
- a $46.6 million decrease in cash paid for acquisitions and investments in and transactions with unconsolidated entities during the year ended March 31, 2018; and
- a $16.9 million payment to terminate a development agreement during the year ended March 31, 2017 (see Note 15 to our consolidated financial statements included in this Annual Report).

These increases in net cash provided by investing activities were partially offset by a $63.2 million increase in cash flows from derivatives.

Net cash used in investing activities was $363.1 million during the year ended March 31, 2017, compared to $445.3 million during the year ended March 31, 2016. The decrease in net cash used in investing activities was due primarily to:

- a decrease in capital expenditures from $536.9 million during the year ended March 31, 2016 to $363.9 million during the year ended March 31, 2017;
- $125.0 million related to the purchase of a 37.5% undivided interest in Grand Mesa Pipeline during the year ended March 31, 2016;
- a $121.1 million decrease in cash paid for acquisitions and investments in unconsolidated entities during the year ended March 31, 2017; and
- a $15.6 million decrease for a loan to Grassland during the year ended March 31, 2016.

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

- a $187.7 million decrease in proceeds from the sale of the general partner interest in TLP during the year ended March 31, 2016 and the sales of TLP common units we owned and Grassland and an increase in proceeds from the sale of excess pipe in our Crude Oil Logistics segment during the year ended March 31, 2017;
- a $143.1 million decrease in cash flows from derivatives; and
- a $16.9 million payment to terminate a development agreement during the year ended March 31, 2017 (see Note 15 to our consolidated financial statements included in this Annual Report).

Financing Activities. Net cash used in financing activities was $394.3 million during the year ended March 31, 2018, compared to net cash provided by financing activities of $371.5 million during the year ended March 31, 2017. The increase in net cash used in financing activities was due primarily to:

- $1.2 billion in proceeds from the issuance of the 2023 Notes and 2025 Notes during the year ended March 31, 2017;
- an increase of $465.5 million for repayments and repurchases of all of our remaining outstanding senior secured notes and a portion of our Senior Unsecured Notes during the year ended March 31, 2018;
- a decrease of $319.4 million in proceeds from the sale of our common units and preferred units during the year ended March 31, 2018;
- an increase of $43.3 million in distributions paid to our general partners and common unitholders, preferred unitholders and noncontrolling interest owners during the year ended March 31, 2018; and
- $26.4 million for the repurchase of a portion of our common units and warrants related to our Class A Preferred Units during the year ended March 31, 2018.

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These increases in net cash used in financing activities were partially offset by:

- an increase of $1.2 billion in borrowings on our revolving credit facilities (net of repayments) during the year ended March 31, 2018;
- the repayment of equipment loans totaling $41.7 million during the year ended March 31, 2017;
- $30.8 million in debt issuance costs for the issuance of the 2023 Notes and 2025 Notes and the amendment and restatement of our Credit Agreement during the year ended March 31, 2017; and
- a $25.9 million release of contingent consideration liabilities related to the termination of a development agreement during the year ended March 31, 2017 (see Note 15 to our consolidated financial statements included in this Annual Report).

Net cash provided by financing activities was $371.5 million during the year ended March 31, 2017, compared to $80.7 million during the year ended March 31, 2016. The increase in net cash provided by financing activities was due primarily to:

- an increase in proceeds from long-term debt (excluding our revolving credit facility) of $1.1 billion due primarily to the issuance of the 2023 Notes and 2025 Notes during the year ended March 31, 2017;
- $522.1 million in proceeds from the sale of our common units and preferred units during the year ended March 31, 2017; and
- a decrease of $172.9 million in distributions paid to our general partners and common unitholders, preferred unitholders and noncontrolling interest owners during the year ended March 31, 2017.

These increases in net cash provided by financing activities were partially offset by:

- a $1.5 billion decrease in borrowings on our revolving credit facilities (net of repayments) during the year ended March 31, 2017; and
- a $25.9 million release of contingent consideration liabilities related to the termination of a development agreement during the year ended March 31, 2017 (see Note 15 to our consolidated financial statements included in this Annual Report).

Distributions Declared

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. See further discussion of our cash distribution policy in Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities included in this Annual Report.

On March 19, 2018, the board of directors of our general partner declared a distribution on the Class B Preferred Units for the three months ended March 31, 2018 of $4.7 million in the aggregate, which was paid to the holders of the Class B Preferred Units on April 16, 2018.

On April 24, 2018, the board of directors of our general partner declared a distribution of $0.39 per common unit to the unitholders of record on May 7, 2018. In addition, the board of directors declared a distribution to the holders of the Class A Preferred Units of $6.4 million in the aggregate. The distributions were paid to both the common unitholders and the holders of the Class A Preferred Units on May 15, 2018.

See Note 10 to our consolidated financial statements included in this Annual Report for a detailed description of the distributions declared and paid for the years ended March 31, 2018, 2017 and 2016.

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Contractual Obligations

The following table summarizes our contractual obligations at March 31, 2018 for our fiscal years ending thereafter:

		Years Ending March 31,					
	Total	2019	2020	2021	2022	2023	Thereafter
Principal payments on long-term debt:							
Expansion capital borrowings	$—	$—	$—	$—	$—	$—	$—
Working capital borrowings	969,500	—	—	—	969,500	—	—
Senior unsecured notes	1,725,554	—	353,424	—	367,048	—	1,005,082
Other long-term debt	11,415	3,196	2,344	5,484	292	81	18
Interest payments on long-term debt:							
Revolving Credit Facility (1)	198,565	55,157	55,157	55,157	33,094	—	—
Senior unsecured notes	601,001	118,235	108,990	99,745	99,745	74,510	99,776
Other long-term debt	1,013	498	341	157	14	2	1
Letters of credit	175,736	—	—	—	175,736	—	—
Future minimum lease payments under noncancelable operating leases	522,507	132,861	115,962	99,312	71,038	53,273	50,061
Future minimum throughput payments under noncancelable agreements (2)	91,580	50,201	41,379	—	—	—	—
Construction commitments (3)	2,671	2,671	—	—	—	—	—
Fixed-price commodity purchase commitments:							
Crude oil	77,015	77,015	—	—	—	—	—
Natural gas liquids	5,616	5,616	—	—	—	—	—
Index-price commodity purchase commitments (4):							—
Crude oil (5)	3,235,777	1,403,823	567,987	453,328	363,302	256,327	191,010
Natural gas liquids	502,428	502,428	—	—	—	—	—
Total contractual obligations	$8,120,378	$2,351,701	$1,245,584	$713,183	$2,079,769	$384,193	$1,345,948

(1) The estimated interest payments on our Revolving Credit Facility are based on principal and letters of credit outstanding at March 31, 2018. See Note 8 to our consolidated financial statements included in this Annual Report for additional information on our Credit Agreement.

(2) We have executed noncancelable agreements with crude oil pipeline operators, which guarantee us minimum monthly shipping capacity on the pipelines. As a result, we are required to pay the minimum shipping fees if actual shipments are less than our allotted capacity. Under certain agreements we have the ability to recover minimum shipping fees previously paid if our shipping volumes exceed the minimum monthly shipping commitment during each month remaining under the agreement, with some contracts containing provisions that allow us to continue shipping up to six months after the maturity date of the contract in order to recapture previously paid minimum shipping delinquency fees. See Note 9 to our consolidated financial statements included in this Annual Report for additional information.

(3) At March 31, 2018, construction commitments relate to the expansion of the Lucerne, Colorado crude oil tank storage.

(4)

Index prices are based on a forward price curve at March 31, 2018. A theoretical change of $0.10 per gallon of natural gas liquids in the underlying commodity price at March 31, 2018 would result in a change of $58.2 million in the value of our index-price natural gas liquids purchase commitments. A theoretical change of $1.00 per barrel of crude oil in the underlying commodity price at March 31, 2018 would result in a change of $61.2 million in the value of our index-price crude oil purchase commitments. See Note 9 to our consolidated financial statements included in this Annual Report for further detail of the commitments.

(5) Our crude oil index-price purchase commitments exceed our crude oil index-price sales commitments (see Note 9 to our consolidated financial statements included in this Annual Report) due primarily to our long-term purchase commitments for crude oil that we purchase and ship on the Grand Mesa Pipeline. As these purchase commitments are deliver-or-pay contracts, we have not entered into corresponding long-term sales contracts for volumes we may not receive.

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Off-Balance Sheet Arrangements

We do not have any off balance sheet arrangements other than the operating leases discussed in Note 9 to our consolidated financial statements included in this Annual Report.

Environmental Legislation

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

Recent Accounting Pronouncements

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

Critical Accounting Policies

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

Revenue Recognition

We record product sales revenues when title to the product transfers to the purchaser, which typically occurs when the purchaser receives the product. We record terminaling, transportation, storage, and service revenues when the service is performed, and we record tank and other rental revenues over the lease term. Revenues for our Water Solutions segment are recognized when we obtain the wastewater at our treatment and disposal facilities.

Derivative Financial Instruments

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

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

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

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Impairment of Long-Lived Assets

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

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

Impairment of Goodwill

Goodwill is subject to at least an annual assessment for impairment. We perform our annual assessment of impairment during the fourth quarter of our fiscal year, and more frequently if circumstances warrant. For purposes of goodwill impairment testing, assets are grouped into "reporting units". A reporting unit is either an operating segment or a component of an operating segment, depending on how similar the components of the operating segment are to each other in terms of operational and economic characteristics. For each reporting unit, we perform a qualitative assessment of relevant events and circumstances about the likelihood of goodwill impairment. If it is deemed more likely than not that the fair value of the reporting unit is less than its carrying amount, we calculate the fair value of the reporting unit. Otherwise, further testing is not required. The qualitative assessment is based on reviewing the totality of several factors, including macroeconomic conditions, industry and market considerations, cost factors, overall financial performance, other entity specific events (for example, changes in management) or other events such as selling or disposing of a reporting unit. The determination of a reporting unit's fair value is predicated on our assumptions regarding the future economic prospects of the reporting unit. Such assumptions include (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management's estimates of operating margins, (ii) long-term growth rates for cash flows beyond the discrete forecast period, (iii) appropriate discount rates and (iv) estimates of the cash flow multiples to apply in estimating the market value of our reporting units. If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings may be required to reduce the carrying value of goodwill to its implied fair value. If future results are not consistent with our estimates, we could be exposed to future impairment losses that could be material to our results of operations. We monitor the markets for our products and services, in addition to the overall market, to determine if a triggering event occurs that would indicate that the fair value of a reporting unit is less than its carrying value. See Note 6 to our consolidated financial statements included in this Annual Report for a further discussion of our goodwill impairment assessment.

Asset Retirement Obligations

We have contractual and regulatory obligations at certain facilities for which we have to perform remediation, dismantlement, or removal activities when the assets are retired. We are required to recognize the fair value of a liability for an asset retirement obligation if a reasonable estimate of fair value can be made. In order to determine the fair value of such a liability, we must make certain estimates and assumptions including, among other things, projected cash flows, the estimated timing of retirement, a credit-adjusted risk-free interest rate, and an assessment of market conditions, which could significantly impact the estimated fair value of the asset retirement obligation. These estimates and assumptions are very subjective and can vary over time. Our consolidated balance sheet at March 31, 2018 includes a liability of $9.1 million related to asset retirement obligations, which is reported within other noncurrent liabilities.

In addition to the obligations described above, we may be obligated to remove facilities or perform other remediation upon retirement of certain other assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminable. We will record an asset retirement obligation for these assets in the periods in which settlement dates are reasonably determinable.

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Depreciation and Amortization Methods and Estimated Useful Lives of Property, Plant and Equipment and Intangible Assets

Depreciation and amortization expense is the systematic write-off of the cost of our property, plant and equipment (net of residual or salvage value, if any) and 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 depreciate our property, plant and equipment and amortize the majority of our intangible assets using the straight-line method, which results in our recording depreciation and amortization expense evenly over the estimated life of the individual asset. The estimate of depreciation and amortization expense requires us to make assumptions regarding the useful economic lives and residual values of our assets. When we acquire and place our property, plant and equipment in service or acquire intangible assets, 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 and amortization 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, changes in expected salvage values or changes in customer attrition rates.

Business Combinations

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

Inventories

Our inventories consist primarily of crude oil, natural gas liquids, gasoline, diesel, ethanol, and biodiesel. Our inventories are valued at the lower of cost or net realizable value, with cost determined using either the weighted-average cost or the first in, first out (FIFO) methods, including the cost of transportation and storage, and with net realizable value defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. In performing this analysis, we consider fixed-price forward commitments and the opportunity to transfer propane inventory from our Liquids business to our Retail Propane business to sell the inventory in retail markets. At the end of each fiscal year, we also perform a “lower of cost or net realizable value” analysis; if the cost basis of the inventories would not be recoverable based on the net realizable value at the end of the year, we reduce the book value of the inventories to the recoverable amount. When performing this analysis during interim periods within a fiscal year, accounting standards do not require us to record a lower of cost or net realizable value write-down if we expect the net realizable value to recover by our fiscal year end. The net realizable values of these commodities change on a daily basis as supply and demand conditions change. We are unable to control changes in the net realizable 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 net realizable 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. The restricted units include both awards that: (i) vest contingent on the continued service of the recipients through the vesting date (the “Service Awards”) and (ii) vest contingent both on the continued service of the recipients through the vesting date and also on the performance of our common units relative to other entities in the Alerian MLP Index (the “Index”) over specified periods of time (the “Performance Awards”). The awards may also vest upon a change of control, at the discretion of the board of directors of our general partner.

Service Awards are valued at the closing price as of the grant date less the present value of the expected distribution stream over the vesting period using a risk-free interest rate. We record the expense for each Service Award on a straight-line basis over the requisite period for the entire award (that is, over the requisite service period of the last separately vesting

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portion of the award), ensuring that the amount of compensation cost recognized at any date at least equals the portion of the grant-date value of the award that is vested at that date.

The fair value of the Performance Awards is estimated using a Monte Carlo simulation at the grant date. The significant inputs used to calculate the fair value of these awards include (i) the price per our common units at the grant date and the beginning of the performance period, (ii) a compounded risk-free interest rate, (iii) our compounded dividend yield, (iv) our historical volatility, (v) the volatility and correlations of our peers and (vi) the remaining performance period. We record the expense for each of the tranches of the Performance Awards on a straight-line basis over the period beginning with the grant date and ending with the vesting date of the tranche. Any Performance Awards that do not become earned Performance Awards will terminate, expire and otherwise be forfeited by the participants.

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 our 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, 2018, we had $969.5 million of outstanding borrowings under our Revolving Credit Facility at a weighted average interest rate of 4.99%. A change in interest rates of 0.125% would result in an increase or decrease of our annual interest expense of $1.2 million, based on borrowings outstanding at March 31, 2018.

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, or refined and renewables products will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract.

Procedures and limits for managing commodity price risks and credit risks are specified in our market risk policy and credit risk policy, respectively. Open commodity positions and market price changes are monitored daily and are reported to senior management and to marketing operations personnel. Credit risk is monitored daily and exposure is minimized through customer deposits, restrictions on product liftings, letters of credit, and entering into master netting agreements that allow for offsetting counterparty receivable and payable balances for certain transactions. At March 31, 2018, our primary counterparties were retailers, resellers, energy marketers, producers, refiners, and dealers.

The crude oil, natural gas liquids, and refined and renewables products industries are “margin-based” and “cost-plus” businesses in which gross profits depend on the differential of sales prices over supply costs. We have no control over market conditions. As a result, our profitability may be impacted by sudden and significant changes in the price of crude oil, natural gas liquids, and refined and renewables products.

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.

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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 in our consolidated statements of operations. The following table summarizes the hypothetical impact on the March 31, 2018 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)	$ (9,943)
Propane (Liquids segment)	$ (64)
Other products (Liquids segment)	$ (238)
Gasoline (Refined Products and Renewables segment)	$ (28,747)
Diesel (Refined Products and Renewables segment)	$ (9,622)
Ethanol (Refined Products and Renewables segment)	$ (3,207)
Biodiesel (Refined Products and Renewables segment)	$ 1,593
Canadian dollars (Liquids segment)	$ 637

Fair Value

We use observable market values for determining the fair value of our derivative instruments. In cases where actively quoted prices are not available, other external sources are used which incorporate information about commodity prices in actively quoted markets, quoted prices in less active markets and other market fundamental analysis.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements beginning on page F-1 of this Annual Report, together with the report of Grant Thornton LLP, our independent registered public accounting firm, are incorporated by reference into this Item 8.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rule 13(a)-15(e) and 15(d)-15(e) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), that are designed to provide reasonable assurance that information required to be disclosed in our filings and submissions under the Exchange Act is recorded, processed, summarized and reported within the periods specified in the rules and forms of the Securities and Exchange Commission (“SEC”) and that such information is accumulated and communicated to our management, including the principal executive officer and principal financial officer of our general partner, as appropriate, to allow timely decisions regarding required disclosure.

We completed an evaluation under the supervision and with participation of our management, including the principal executive officer and principal financial officer of our general partner, of the effectiveness of the design and operation of our disclosure controls and procedures at March 31, 2018. Based on this evaluation, the principal executive officer and principal financial officer of our general partner have concluded that as of March 31, 2018, such disclosure controls and procedures were effective to provide the reasonable assurance described above.

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.

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Based on our evaluation under the COSO framework, our management concluded that our internal control over financial reporting was effective as of March 31, 2018.

Our internal control over financial reporting as of March 31, 2018 has been audited by Grant Thornton LLP, an independent registered public accounting firm, as stated in their report, which appears in Part IV, Item 15 - “Exhibits, Financial Statement Schedules” in this Annual Report.

Changes in Internal Control Over Financial Reporting

Other than changes that have resulted or may result from our business combinations during the year ended March 31, 2018, 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, 2018 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

We closed several business combinations during the year ended March 31, 2018, as described in Note 4 to our consolidated financial statements included in this Annual Report. At this time, we continue to evaluate the business and internal controls and processes of these acquired businesses and are making various changes to their operating and organizational structure based on our business plan. We are in the process of implementing our internal control structure over these acquired businesses. We expect that our evaluation and integration efforts related to those combined operations will continue into future fiscal quarters.

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. James C. Kneale, Mr. Stephen L. Cropper, and Mr. James M. Collingsworth satisfy the New York Stock Exchange ("NYSE") and SEC independence requirements. The NYSE does not require a listed publicly traded limited partnership like us to have a majority of independent directors on the board of directors of our general partner. In addition, we are not required to have a nominating and corporate governance committee.

In evaluating director candidates, the NGL Energy GP Investor Group assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skill and expertise that are likely to enhance the ability of the board of directors of our general partner to manage and direct our affairs and business, including, when applicable, to enhance the ability of committees of the board to fulfill their duties. Our general partner has no minimum qualifications for director candidates. In general, however, the NGL Energy GP Investor Group reviews and evaluates both incumbent and potential new directors in an effort to achieve diversity of skills and experience among the directors of our general partner and in light of the following criteria:

- experience in business, government, education, technology or public interests;
- high-level managerial experience in large organizations;
- breadth of knowledge regarding our business and industry;
- specific skills, experience or expertise related to an area of importance to us, such as energy production, consumption, distribution or transportation, government, policy, finance or law;
- moral character and integrity;
- commitment to our unitholders' interests;
- ability to provide insights and practical wisdom based on experience and expertise;
- ability to read and understand financial statements; and
- ability to devote the time necessary to carry out the duties of a director, including attendance at meetings and consultation on partnership matters.

Although our general partner does not have a formal policy in regard to the consideration of diversity in identifying director nominees, qualified candidates for nomination to the board are considered without regard to race, color, religion, gender, ancestry or national origin.

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Directors and Executive Officers

Directors of our general partner are appointed by the NGL Energy GP Investor Group and hold office until their successors have been duly elected and qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers are appointed by, and serve at the discretion of, the board of directors of our general partner. The following table summarizes information regarding the current directors of our general partner and our executive officers.

Name	Age	Position with NGL Energy Holdings LLC
H. Michael Krimbill	64	Chief Executive Officer and Director
Robert W. Karlovich III	41	Chief Financial Officer and Treasurer
Vincent J. Osterman	61	President, Retail Propane Operations and Director
Kurston P. McMurray	46	General Counsel and Corporate Secretary
Lawrence J. Thuillier	47	Chief Accounting Officer
Shawn W. Coady	56	Director
James M. Collingsworth	63	Director
Stephen L. Cropper	68	Director
Bryan K. Guderian	58	Director
James C. Kneale	66	Director
Jared Parker	36	Director
John T. Raymond	47	Director
L. John Schaufele IV	35	Director

H. Michael Krimbill. Mr. Krimbill has served as our Chief Executive Officer since October 2010 and as a member of the board of directors of our general partner since its formation in September 2010. From February 2007 through September 2010, Mr. Krimbill managed private investments. Mr. Krimbill was the President and Chief Financial Officer of Energy Transfer Partners, L.P. from 2004 until his resignation in January 2007. Mr. Krimbill joined Heritage Propane Partners, L.P., the predecessor of Energy Transfer Partners, L.P., as Vice President and Chief Financial Officer in 1990. Mr. Krimbill was President of Heritage Propane Partners, L.P. from 1999 to 2000 and President and Chief Executive Officer of Heritage Propane Partners, L.P. from 2000 to 2005. Mr. Krimbill also served as a director of Energy Transfer Equity, the general partner of Energy Transfer Partners, L.P., from 2000 to January 2007, Williams Partners L.P. from 2007 to September 2012, and Pacific Commerce Bank from January 2011 to March 2015.

Mr. Krimbill brings leadership, oversight and financial experience to the board. Mr. Krimbill provides expertise in managing and operating a publicly traded partnership, including substantial expertise in successfully acquiring and integrating propane and midstream businesses. Mr. Krimbill also brings financial expertise to the board, including his prior service as a chief financial officer. Mr. Krimbill's experience serving on other public company boards is also a valuable asset to our board of directors.

Robert W. Karlovich III. Mr. Karlovich has served as our Chief Financial Officer since February 2016. Prior to joining NGL, Mr. Karlovich served as Chief Financial Officer of Targa Pipeline Partners, a subsidiary of Targa Resources Partners, LP, from February 2015 through February 2016, and as Senior Vice President of Commercial and Business Development for Targa Resources Partners, LP from November 2015 to February 2016. Mr. Karlovich served in various roles at Atlas Pipeline Partners, L.P. and its subsidiaries ("APL") from September 2006 to February 2015 when APL merged with Targa Resources Partners, LP. Mr. Karlovich served in various roles at Syntroleum Corporation from February 2004 to September 2006. Prior to that, Mr. Karlovich worked at Arthur Andersen LLP and Grant Thornton LLP. Mr. Karlovich is a certified public accountant.

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 Retail Propane Operations and as a member of the board of directors of our general partner since October 2011. Mr. Osterman also currently serves on the board of directors of Energi Holdings, Inc. and on the Board of Advisors of the Gaudette Insurance Agency.

With his long tenure as President of the Osterman Associated Companies, Mr. Osterman brings valuable executive and operational experience in the retail propane businesses to the board. Mr. Osterman also provides insight into developments and trends in the propane industry through his leadership roles in industry associations.

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Kurston P. McMurray. Mr. McMurray has served as our General Counsel and Corporate Secretary since October 2016. Mr. McMurray joined NGL in February 2015 as Vice President, Legal and Corporate Secretary. Prior to joining NGL, Mr. McMurray practiced law in the Tulsa, Oklahoma area since 1998 and was a founding shareholder of Wilkin/McMurray PLLC. Mr. McMurray's private practice specialized in business transactions, real estate, healthcare, banking, corporate governance, corporate management and commercial litigation.

Lawrence J. Thuillier. Mr. Thuillier has served as our Chief Accounting Officer since January 2016. Prior to joining NGL, Mr. Thuillier served in various roles at Eagle Rock Energy Partners, L.P. from December 2007 through October 2015, most recently as Vice President of Financial Reporting and Corporate Controller. Mr. Thuillier served as Assistant Corporate Controller for Exterran Holdings, Inc. (formerly Universal Compression) from November 2006 through November 2007. Prior to that, Mr. Thuillier served in various roles at Deloitte & Touche LLP, most recently as Audit Senior Manager.

Shawn W. Coady. Dr. Coady had 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. On March 30, 2018, Dr. Coady, as a result of the sale of a portion of our Retail Propane segment (see Note 15 to our consolidated financial statements included in this Annual Report for a further discussion), Dr. Coady resigned from his position as President and Chief Operating Officer, Retail Division, but will remain as a member of the board of directors. Dr. Coady served as a member of the board of directors of our general partner since its formation in September 2010. Dr. Coady served as an officer of Hicks Oils & Hicksgas, Incorporated ("HOH"), from March 1989 to September 2010 when HOH contributed its propane and propane related assets to Hicksgas LLC, and the membership interests in Hicksgas LLC were contributed to us as part of our formation transactions. Dr. Coady was also the President of Hicksgas Gifford, Inc. from March 1989 until the membership interests in the company were contributed to us as part of our formation transactions. Dr. Coady has served as a director for the National Propane Gas Association from 2004 to 2015 and as a member of the executive committee of the Illinois Propane Gas Association from 2004 to March 2015.

Dr. Coady brings valuable operational experience to the board. Dr. Coady has over 25 years of experience in the retail propane industry, and provides expertise in both acquisition and organic growth strategies. Dr. Coady also provides insight into developments and trends in the propane industry through his leadership roles in industry associations.

James M. Collingsworth. Mr. Collingsworth has served on the board of directors of our general partner since January 2015. Mr. Collingsworth previously served as a Senior Vice President of the general partner of Enterprise Products Partners L.P. from November 2001 through January 2014. 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. and American Ethane Co.

Mr. Collingsworth brings a wealth of in-depth industry experience to the board. 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 Executive Vice President of Business Development of WPX Energy, Inc. ("WPX") since February 2018.

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Mr. Guderian served as Senior Vice President of Business Development of WPX from October 2014 to February 2018 and 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 served as a director of Apco Oil & Gas International Inc., from 2002 to 2015 and as a director of Petrolera Entre Lomas S.A. from 2003 to 2015.

Mr. Guderian brings considerable upstream experience to the board including executive, operational and financial expertise from 30 years of petroleum industry involvement, the majority of which has been focused in exploration and production.

James C. Kneale. Mr. Kneale joined the board of directors of our general partner in May 2011. Mr. Kneale served as President and Chief Operating Officer of ONEOK, Inc., from January 2007, and ONEOK Partners, L.P., from May 2008, until his retirement in January 2010. After joining ONEOK in 1981, Mr. Kneale served in various other roles, including Chief Financial Officer from 1999 through 2006. Mr. Kneale also served as a director of ONEOK Partners, L.P. from 2006 until his retirement in January 2010.

Mr. Kneale brings extensive executive, financial and operational experience to the board. With nearly 30 years of experience in the natural gas liquids industry in numerous positions, Mr. Kneale provides valuable insight into our business and industry.

Jared Parker. Mr. Parker joined the board of directors of our general partner in January 2017. Mr. Parker had previously been an observer on the board since May 2016. Mr. Parker is a Managing Director and Portfolio Manager of Oaktree Capital Management L.P.'s ("Oaktree") Infrastructure Investing Strategy. Mr. Parker joined Oaktree in August 2014 from Highstar Capital and has over 13 years of experience in private equity, operational leadership, investment banking and finance. Mr. Parker currently serves as a director on the board of ADS Waste Holdings, Inc. Previously Mr. Parker served on the boards of London City Airport and the Ports America Companies and as an observer to the boards of InterGen and Northern Star Generation. Mr. Parker served as president of Ports America Stevedoring, the largest business unit inside Ports America from 2010 through 2013. Prior to joining Highstar Capital in 2005, Mr. Parker worked as an advisor to the Highstar Capital Team on several transactions as an investment banker at Deutsche Bank. While at Deutsche Bank, Mr. Parker advised domestic and power generation companies and financial sponsors on merger and acquisitions and financings.

Mr. Parker brings experience in operational leadership and finance to the board. As a director for other public companies, Mr. Parker also provides cross board experience.

John T. Raymond. Mr. Raymond joined the board of directors of our general partner in August 2013. Mr. Raymond is the Founder and Majority Owner of The Energy & Minerals Group ("EMG") of which he has been a Managing Partner and the Chief Executive Officer since its September 2006 inception. Mr. Raymond has held executive leadership positions with various energy companies, including President and Chief Executive Officer of Plains Resources Inc. (the predecessor entity of Vulcan Energy Corporation), President and Chief Operating Officer of Plains Exploration and Production Company and was a Director of Plains All American Pipeline, LP.

Mr. Raymond also currently serves as 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, PAA GP Holdings LLC, Tallgrass MLP GP LLC and Tallgrass Management, LLC. Mr. Raymond manages various private investments through personally held Lynx Holdings, LLC.

Mr. Raymond brings extensive financial and industry experience to the board. As a director for other public companies, Mr. Raymond also provides cross board experience.

L. John Schaufele IV. Mr. Schaufele joined the board of directors of our general partner in February 2018. Mr. Schaufele has worked at EMG since 2011. Mr. Schaufele previously worked at a middle-market private equity investment firm and JPMorgan. Mr. Schaufele currently serves as a director of Ascent Resources, LLC, Heritage NonOp Holdings, LLC, Heritage Minerals Holdings, LLC, White Star Petroleum Holdings, LLC, and Utica Minerals Development, LLC. Mr. Schaufele received a B.S. in Business and Accounting from Washington & Lee University.

Mr. Schaufele brings extensive financial and industry experience to the board. With 14 years of experience in the energy sector, Mr. Schaufele provides valuable insight into our business.

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Director Appointment Rights

The Limited Liability Company Agreement of NGL Energy Holdings LLC grants certain parties the right to designate a specified number of persons to serve on the board of directors. EMG NGL HC LLC has the right to designate two persons to serve on the board of directors, and has designated John T. Raymond and L. John Schaufele IV. 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) 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. Oaktree has the right to designate one person to serve on the board of directors, and has designated Jared Parker.

Board Leadership Structure and Role in Risk Oversight

The board of directors of our general partner believes that whether the offices of chairman of the board and chief executive officer are combined or separated should be decided by the board, from time to time, in its business judgment after considering relevant circumstances. The board of directors of our general partner currently does not have a chairman.

The board of directors and its committees regularly review material operational, financial, compensation and compliance risks with senior management. In particular, the audit committee is responsible for risk oversight with respect to financial and compliance risks and risks relating to our audit and independent registered public accounting firm. Our compensation committee considers risk in connection with its design and evaluation of compensation programs for our senior management. Each committee regularly reports to the board of directors.

Audit Committee

The board of directors of our general partner has established an audit committee. The audit committee assists the board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has the sole authority to, among other things:

- retain and terminate our independent registered public accounting firm;
- approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm; and
- establish policies and procedures for the pre-approval of all non-audit services and tax services to be rendered by our independent registered public accounting firm.

The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm is given unrestricted access to the audit committee and our management, as necessary.

Mr. Collingsworth, Mr. Cropper, and Mr. Kneale currently serve on the audit committee, and Mr. Kneale serves as the chairman. The board of directors of our general partner has determined that Mr. Kneale is an "audit committee financial expert" as defined under SEC rules and that each member of the audit committee is financially literate. In compliance with the requirements of the NYSE, all of the members of the audit committee are independent directors, as defined in the applicable NYSE and Exchange Act rules.

Compensation Committee

The board of directors of our general partner has established a compensation committee. The compensation committee's responsibilities include the following, among others:

- establishing the general partner's compensation philosophy and objectives;
- approving the compensation of the Chief Executive Officer;
- making recommendations to the board of directors with respect to the compensation of other officers and directors; and
- reviewing and making recommendations to the board of directors with respect to incentive compensation and equity-based plans.

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Mr. Cropper, Mr. Guderian, and Mr. Kneale currently serve on the compensation committee. Mr. Cropper serves as the chairman. The board of directors has determined that Mr. Cropper and Mr. Kneale are independent directors under applicable NYSE and Exchange Act rules. The NYSE does not require a listed publicly traded limited partnership to have a compensation committee consisting entirely of independent directors.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's board of directors and officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of beneficial ownership and reports of changes in beneficial ownership of our common units and other equity securities with the SEC. Directors, officers and greater than 10% unitholders are required by SEC regulations to furnish to us copies of all Section 16(a) forms they file with the SEC.

To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations by our directors and officers, we believe that all reporting obligations of our general partner's directors and officers and our greater than 10% unitholders under Section 16(a) were satisfied during the year ended March 31, 2018, except for the withholding of units to satisfy tax obligations in connection with the LTIP vesting in February 2018, which was delayed for four officers and one director due to an administrative error by our third-party vendor.

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, 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 "2018" in the Compensation Discussion and Analysis and the summary compensation table refers to our fiscal year ended March 31, 2018.

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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 2018 were:

- H. Michael Krimbill–Chief Executive Officer
- Robert W. Karlovich III–Executive Vice President and Chief Financial Officer
- Vincent J. Osterman–President, Retail Propane Operations
- Lawrence J. Thuillier–Chief Accounting Officer
- Kurston P. McMurray–Executive Vice President and General Counsel and Secretary

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, 2018 included the following:

- Issued 9.00% Class B Preferred Units for net proceeds of $202.7 million;
- Sold our 50% interest in Glass Mountain for net proceeds of $292.1 million;
- Sold a portion of our Retail Propane segment for net proceeds of $212.4 million; and
- Sold a portion of our Sawtooth salt dome cavern facility for cash of $37.6 million and the contribution of certain refined products rights.

Compensation Highlights

- We paid cash bonuses to Mr. Karlovich and Mr. McMurray during fiscal year 2018, primarily due to their work related to the sale of our 50% interest in Glass Mountain and the sale of a portion of our Retail Propane segment.

- 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.

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Factors Enhancing Alignment with Unitholder Interests

- Majority of officer pay is at risk incentive compensation based on annual financial performance and growth in unitholder value;
- Equity-based incentives are the largest single component of officer compensation;
- Certain of the officers' equity awards are subject to achievement of above-median total unitholder return relative to our performance peer group;
- No excise tax gross-ups; and
- Compensation committee engages an independent compensation adviser.

Compensation Setting Process

Our compensation program for our named executive officers supports our philosophy of pay-for-performance.

- Role of Management: Our Chief Executive Officer also provides periodic recommendations to the compensation committee and the board of directors regarding the compensation of our other named executive officers.
- Role of the Compensation Committee's Consultant: In carrying out its responsibilities for establishing, implementing and monitoring the effectiveness of our executive compensation philosophy, plans and programs, our compensation committee has the authority to engage outside experts to assist in its deliberations. During fiscal year 2018, 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 2018:

PM&P did not provide any services to the Partnership or management other than compensation consulting services requested by or with the approval of the compensation committee;
PM&P does not provide, directly or indirectly through affiliates, any non-compensation services such as pension consulting or human resource outsourcing;
PM&P maintains a conflicts policy, which was provided to the compensation committee with specific policies and procedures designed to ensure independence;
Fees paid to PM&P by the Partnership during fiscal year 2018 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 2018 compensation program.

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Elements of Executive Compensation

As part of our pay-for-performance approach to executive compensation, the compensation of our executive officers includes a significant component of incentive compensation based on our performance. The following table summarizes the primary elements of compensation in our executive compensation program:

Element	Primary Purpose	How Amount Determined	Objective Supported		
			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		
Discretionary Cash Bonus Awards	Rewards achievement of specific annual financial and operational performance goals Recognizes individual contributions to our performance	Based on the named executive officer's relative contribution to achieving or exceeding annual goals	X	X	X
Long-Term Equity Incentive Awards	Motivates and rewards the achievement of long-term performance goals, including increasing the market price of our common units and the quarterly distributions to our unitholders Provides a forfeitable long-term incentive to encourage executive retention	Based on the named executive officer's expected contribution to long-term performance goals	X	X	X

Base Salary

The compensation committee periodically reviews the base salaries of our named executive officers and may recommend adjustments as necessary. We do not make automatic annual adjustments to base salary.

- Mr. Krimbill's initial base salary of $120,000 was originally determined as part of the negotiations for our formation transactions. In setting the base salaries, the parties considered various factors, including the compensation needed to attract or retain the officers, the historical compensation of the officers, and each officer's expected individual contribution to our performance. At the request of Mr. Krimbill, the parties agreed that he should receive a lower base salary than our other executive officers at the time because, as our Chief Executive Officer, a significant portion of his compensation should be performance-based, to further align his interests with the interests of our unitholders. In February 2012, the base salary of Mr. Krimbill was reduced to $60,000, based on our operating and financial performance as a result of an unusually warm winter. The base salary of Mr. Krimbill was restored to $120,000 effective November 12, 2012. Effective July 1, 2014, the board of directors increased Mr. Krimbill's salary to $350,000, in consideration of the fact that his salary was low relative to the benchmark peer group (and remains below the 25th percentile of the peer group). Effective April 1, 2018, Mr. Krimbill's base salary was increased to $625,000, in consideration of the fact that his salary was low relative to the benchmark peer group.

- Mr. Karlovich's base salary of $400,000 was negotiated prior to his joining our management team in February 2016. Mr. Karlovich's base salary was increased to $430,000 in April 2017.
- 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, to $250,000 in July 2013 and increased to $315,000 effective April 2, 2017, in consideration of the fact that his salary was low relative to the benchmark peer group.
- Mr. Thuillier's base salary of $250,000 was negotiated prior to his joining our management team in January 2016. In April 2017, Mr. Thuillier's base salary was increased to $260,000. Effective April 1, 2018, Mr. Thuillier's base salary was increased to $267,800.

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- Mr. McMurray's base salary of $250,000 was negotiated prior to his joining our management team in February 2015. Mr. McMurray's base salary was increased to $300,000 in April 2017. Effective April 1, 2018, Mr. McMurray's base salary was increased to $350,000.

Cash Bonus Awards

None of the named executive officers is subject to a formal cash bonus plan, and any cash bonuses are at the discretion of the compensation committee or the board of directors (in the case of Mr. Krimbill) or the compensation committee (in the case of the other named executive officers). Cash bonuses of $430,000 and $300,000 were paid to Mr. Karlovich and Mr. McMurray, respectively, during fiscal year 2018, primarily due to their work related to the sale of our 50% interest in Glass Mountain and the sale of a portion of our Retail Propane segment.

Long-Term Equity Incentive Awards

Certain restricted units granted to the named executive officers vest in tranches, contingent only on the continued service of the recipient through the vesting date (the "Service Awards"). The following table summarizes Service Award units granted, vested and/or forfeited during fiscal year 2018 with respect to the named executive officers:

	Unvested Units at March 31, 2017	Units Granted	Units Vested	Unvested Units at March 31, 2018
H. Michael Krimbill (1)	300,000	—	(100,000)	200,000
Robert W. Karlovich III (2)	75,000	25,000	(37,500)	62,500
Vincent J. Osterman (3)	60,000	20,000	(30,000)	50,000
Lawrence J. Thuillier (4)	30,000	20,149	(25,149)	25,000
Kurston P. McMurray (5)	45,000	15,000	(22,500)	37,500

(1) Mr. Krimbill vested in 100,000 Service Awards on July 10, 2017.

(2) Mr. Karlovich vested in 25,000 and 12,500 Service Awards on July 10, 2017 and February 13, 2018, respectively. He was granted 25,000 Service Awards on January 10, 2018, of which 12,500 vests on each of February 11, 2020 and November 10, 2020, respectively.

(3) Mr. Osterman vested in 20,000 and 10,000 Service Awards on July 10, 2017 and February 13, 2018, respectively. He was granted 20,000 Service Awards on January 10, 2018, of which 10,000 vests on each of February 11, 2020 and November 10, 2020, respectively.

(4) Mr. Thuillier vested in Service Awards of 10,000 on July 10, 2017, 10,149 on November 10, 2017 and 5,000 on February 13, 2018. He was granted 10,149 Service Awards on November 10, 2017 and 10,000 Service Awards on January 10, 2018, of which 5,000 vests on each of February 11, 2020 and November 10, 2020, respectively.

(5) Mr. McMurray vested in 15,000 and 7,500 Service Awards on July 10, 2017 and February 13, 2018, respectively. He was granted 15,000 Service Awards on January 10, 2018, of which 7,500 vests on each of February 11, 2020 and November 10, 2020, respectively.

The Service Award units granted to the named executive officers, other than to Mr. Krimbill, were determined by reference to our peer group and the market-based benchmarks compiled by PM&P and were based on the named executive officers total compensation falling between the 25th and 50th percentile of the peer group.

The Service Award units granted in November 2017 were intended as a discretionary bonus for performance during fiscal year ended March 31, 2017.

The following table summarizes the vesting dates of the unvested Service Award units at March 31, 2018:

	Service Award Units Vesting By Fiscal Year Ending March 31, 2019	March 31, 2020	March 31, 2021	Unvested Units at March 31, 2018
H. Michael Krimbill (1)	100,000	100,000	—	200,000
Robert W. Karlovich III (2)	25,000	25,000	12,500	62,500
Vincent J. Osterman (2)	20,000	20,000	10,000	50,000
Lawrence J. Thuillier (2)	10,000	10,000	5,000	25,000
Kurston P. McMurray (2)	15,000	15,000	7,500	37,500

(1) Mr. Krimbill’s Service Awards will vest 100,000 on each of July 9, 2018 and July 8, 2019, respectively.

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(2) Mr. Karlovich, Mr. Osterman, Mr. Thuillier and Mr. McMurray all agreed to amend the vesting terms of their Service Awards that were originally scheduled to vest on July 9, 2018 and July 8, 2019 (see Note 10 to our consolidated financial statements included in this Annual Report for a further discussion of the split vesting). For the year ending March 31, 2019, half of the units will vest on November 13, 2018 and the other half on February 12, 2019. For the year ending March 31, 2020, half of the units will vest on November 13, 2019 and February 11, 2020. For the year ending March 31, 2021, the units will vest on November 10, 2020.

During April 2015, the Partnership granted awards that are contingent both on the continued service of the recipients through the vesting date and also on the performance of our common units relative to the performance of other entities in the Alerian MLP Index (the "Index") over specified periods of time (the "Performance Awards").

The Performance Awards represent hypothetical units and are not actual common units. The Performance Awards settle in common units rather than cash. The right to receive common units with respect to the Performance Awards depends on (i) the level of total unitholder return ("TUR") attained by us over the applicable performance periods, as measured against our peer group and as described in the Performance Unit Agreement, provided that the number of common units that may be earned in respect of the Performance Awards will either be 0% of the Performance Awards, for performance at anything less than the 50th percentile of the performance peer group, or in a range of 50% to 200% of the Performance Awards, for performance from the 50th percentile to the 90th percentile of the performance peer group over the same performance period (such number of earned Performance Awards are referred to, and defined in the Performance Unit Agreement, as, "Earned Performance Awards"), and (ii) the satisfaction of a continued service requirement.

The following table summarizes the maximum number of units that could vest from the Performance Awards granted to each named executive officer during the fiscal year ended March 31, 2018:

	Maximum Performance Award Units by Vesting Date
	July 1, 2020
Robert W. Karlovich III	50,000
Vincent J. Osterman	40,000
Lawrence J. Thuillier	20,000
Kurston P. McMurray	30,000

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. As of March 31, 2018, performance will be measured over the following periods:

Vesting Date of Tranche	Performance Period for Tranche
July 1, 2018	July 1, 2015 through June 30, 2018
July 1, 2019	July 1, 2016 through June 30, 2019
July 1, 2020	July 1, 2017 through June 30, 2020

The following table summarizes the percentage of the maximum Performance Award units that will vest depending on the percentage of entities in the Index that NGL outperforms:

Our Relative Total Unitholder Return Percentile Ranking	Payout (% of Target Units)
Less than 50th percentile	0%
Between the 50th and 75th percentile	50%–100%
Between the 75th and 90th percentile	100%–200%
Above the 90th percentile	200%

The Performance Award units were granted in consideration of the fact that the base salaries and the service-based equity awards for the named executive officers are in most cases below the median value for officers in their respective peer groups. The compensation committee believes that if the performance of NGL's common units falls below the median performance of the Index, the named executive officers should receive lower compensation than their peers, but that if the performance of NGL's common units exceeds the median of the Index, the compensation of the named executive officers should be increased.

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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, other than to Mr. McMurray, who is entitled to receive severance benefits pursuant to his employment agreement in the event of certain terminations of his employment (as described below after the "Summary Compensation Table" under the heading, "Employment Agreement with Mr. McMurray"). The board of directors has the option to accelerate the vesting of the restricted units in the event of a change in control of the Partnership, although it is not under any obligation to do so. If the board of directors were to exercise its discretion to accelerate the vesting of restricted units upon a change in control, the value of such units would be the same as reported in the "Outstanding Equity Awards at March 31, 2018" table below.

401(k) Plan

We have established a defined contribution 401(k) plan to assist our eligible employees in saving for retirement on a tax-deferred basis. The 401(k) plan permits all eligible employees, including our named executive officers, to make voluntary pre-tax contributions to the plan, subject to applicable tax limitations. For every dollar that employees contribute up to 1% of their eligible compensation (as defined in the plan), we contribute one dollar, plus 50 cents for every dollar employees contribute between 1% and 6% of their eligible compensation (as defined in the plan). Our matching contributions prior to January 1, 2015 vest over five years and, effective January 1, 2015, our matching contributions vest over two 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 2018 Compensation Program

During fiscal year 2018, 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

AmeriGas Partners LP	NuStar Energy L.P.	Martin Midstream Partners LP

Ferrellgas Partners LP	Targa Resources Partners LP	Regency Energy Partners LP
Star Gas Partners, L.P.	Buckeye Partners, L.P.	Boardwalk Pipeline Partners, LP
Suburban Propane Partners, L.P.	Genesis Energy LP	Western Gas Partners LP
ONEOK Partners, L.P.	Crestwood Midstream Partners LP	
Williams Partners L.P.	Magellan Midstream Partners LP	
Enbridge Energy Partners, L.P.	DCP Midstream Partners LP	

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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 2018 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, other than Mr. McMurray (as described below after the “Summary Compensation Table” under the heading, “Employment Agreement with Mr. McMurray”).

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 2018, 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 2018. Shawn W. Coady was an executive officer and is still a member of the board of directors of our general partner. Dr. Coady also serves on the board of directors of HOH, a family-owned company, and in this capacity Dr. Coady participates in the compensation setting process of the HOH board of directors.

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Summary Compensation Table for 2018

The following table summarizes the compensation earned by our named executive officers for fiscal years 2016 through 2018.

Name and Position	Fiscal Year	Salary ($)	Bonus ($)	Restricted Unit Awards (Service and Performance Awards) (1) ($)	All Other Compensation (2) ($)	Total ($)
H. Michael Krimbill	2018	350,000	—	—	10,891	360,891
Chief Executive Officer	2017	350,000	—	7,174,094	10,463	7,534,557
	2016	350,000	—	8,319,437	7,539	8,676,976
Robert W. Karlovich III (3)	2018	428,846	430,000	711,291	9,079	1,579,216
Executive Vice President and	2017	400,000	—	809,985	5,510	1,215,495
Chief Financial Officer	2016	30,769	—	419,250	—	450,019
Vincent J. Osterman	2018	312,500	—	569,032	44,926	926,458
President, Retail Propane Operations	2017	250,000	—	1,662,027	36,831	1,948,858
	2016	250,000	—	1,047,241	30,906	1,328,147
Lawrence J. Thuillier (4)	2018	259,615	—	414,525	9,357	683,497
Chief Accounting Officer	2017	250,000	—	374,007	43,469	667,476
Kurston P. McMurray (5)	2018	298,077	300,000	426,774	8,182	1,033,033
Executive Vice President and						
General Counsel and Secretary						

(1) The fair values of the restricted units shown in the table above were calculated based on the closing market prices of our common units on the grant dates, with adjustments made to reflect the fact that the restricted units are not entitled to distributions during the vesting period. The impact of the lack of distribution rights during the vesting period was estimated using the value of the most recent distribution prior to the grant date and assumptions that a market participant might make about future distribution growth. This calculation of fair value is consistent with the provisions of Accounting Standards Codification ("ASC") 718 Stock Compensation. The following table summarizes these amounts:

Name	Service Award Grant Date Fair Value	Performance Award Grant Date Fair Value	Total Grant Date Fair Value	Performance Awards at Maximum Value
Robert W. Karlovich III	$294,041	$ 417,250	$711,291	$ 834,500
Vincent J. Osterman	$235,232	$ 333,800	$569,032	$ 667,600
Lawrence J. Thuillier	$247,625	$ 166,900	$414,525	$ 333,800
Kurston P. McMurray	$176,424	$ 250,350	$426,774	$ 500,700

(2)

The amounts in this column include matching contributions to our 401(k) plan. 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). Amounts for Mr. Thuillier for fiscal year 2017 include moving expenses. The following table summarizes these amounts:

Name	Fiscal Year	401(k) Match	Moving Expenses	Propane	Total Other Compensation
Vincent J. Osterman	2018	$6,273	$ —	$38,653	$ 44,926
	2017	$5,721	$ —	$31,110	$ 36,831
	2016	$4,038	$ —	$26,868	$ 30,906
Lawrence J. Thuillier	2017	$5,721	$ 37,748	$—	$ 43,469

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(3) Mr. Karlovich was hired in February 2016.
(4) Mr. Thuillier was not a named executive officer prior to fiscal year 2017.
(5) Mr. McMurray was not a named executive officer prior to fiscal year 2018.

Employment Agreement with Mr. McMurray

Mr. McMurray is party to an employment agreement with the Partnership, dated March 10, 2017. The agreement has a term of five years from the effective date, subject to automatic renewals for one-year periods thereafter unless either party provides 60 days' notice of non-renewal of the term. The agreement provides that Mr. McMurray will receive a base salary of no less than $250,000 per year and will be eligible to receive an annual bonus with respect to each fiscal year of the Partnership at a target of 100% of his base salary. Mr. McMurray is also entitled to receive annual awards of unvested units under the Partnership's LTIP.

In the event that Mr. McMurray's employment is terminated by the Partnership without "cause" (as defined in his agreement), provided that he executes a general release of claims, Mr. McMurray is entitled to receive (i) continued payment of his base salary for 12 months following the termination, (ii) the guaranteed unit awards that would have been paid or granted to Mr. McMurray had Mr. McMurray remained employed for an additional three years following his termination, and (iii) his target annual bonus for the performance year in which his termination occurs. Mr. McMurray would also be entitled to receive the severance benefits described in the foregoing sentence in the event that he voluntarily resigns due to a "constructive discharge," which circumstances would include (1) a reduction of Mr. McMurray's annual base salary below $250,000 (other than an across-the-board, pro rata reduction of no more than 10% applicable to all similarly situated executives of the Partnership) or the Partnership's failure to provide Mr. McMurray's elements of compensation, (2) the removal of Mr. McMurray from the position of Senior Vice President, General Counsel and Corporate Secretary without Mr. McMurray's written consent, (3) any action by the Partnership that results in significant diminution of Mr. McMurray's authority, power or responsibilities, or (4) the Partnership's relocation of its principal place of business in Oklahoma to a location more than 50 miles from its current location. Mr. McMurray is subject to non-disclosure and intellectual property rights assignment obligations, and an obligation not to solicit customers, employees or consultants lasting during his employment and for a period of 12 months thereafter.

Restricted Unit Awards

During fiscal year 2018, the compensation committee granted awards for which units vest at specified dates, contingent only on the continued service of the recipient through the service date (the "Service Awards") and awards that vest at specific dates, contingent on both the performance of our common units relative to the performance of other entities and on the continued service of the recipient through the vesting (the "Performance Awards").

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2018 Grants of Plan Based Awards Table

The following table summarizes the number of restricted Service and Performance Award units granted to our named executive officers, and their grant date fair values:

			Estimated Future Payouts Under Performance Awards (1)			
Name	Grant Date	Total Number of Service Award Units	Threshold (#) 50%	Target (#) 100%	Maximum (#) 200%	Grant Date Fair Value of Unit Awards ($)(2)(3)
Robert W. Karlovich III	January 10, 2018	25,000				294,041
	January 10, 2018		12,500	25,000	50,000	417,250
Vincent J. Osterman	January 10, 2018	20,000				235,232
	January 10, 2018		10,000	20,000	40,000	333,800
Lawrence J. Thuillier	November 10, 2017	10,149				130,009
	January 10, 2018	10,000				117,616
	January 10, 2018		5,000	10,000	20,000	166,900
Kurston P. McMurray	January 10, 2018	15,000				176,424
	January 10, 2018		7,500	15,000	30,000	250,350

(1) Amounts reported in the (a) “Threshold” column reflect the threshold number of Performance Awards (at 50% of target) that may be earned (assuming a relative TUR at the 50th percentile), (b) “Target” column reflect the target number of Performance Awards, or 100%, that may be earned (assuming a relative TUR at the 75th percentile) and (c) “Maximum” column reflect 200% of the target Performance Awards that may be earned (assuming a relative TUR greater than the 90th percentile). The number of common units actually received by a named executive officer with respect to a Performance Award may vary based on the Partnership’s relative TUR as compared to the TUR of the performance peer group. The Performance Awards are described above under “Long-Term Equity Incentive Awards” in the Compensation Discussion and Analysis.

(2) The disclosure reflects the aggregate grant date fair value of the Performance Awards, computed in accordance with FASB ASC Topic 718 based on probable achievement of the performance conditions, which is consistent with the estimate of aggregate compensation to be recognized over the service period, excluding the effect of estimated forfeitures.

(3) The fair value of the restricted Service Award units shown in the table above was calculated based on the closing market price of our common units on the grant dates, with adjustments made to reflect the fact that restricted units are not entitled to distributions during the vesting period.

We record the expense for each Service Award on a straight-line basis over the requisite period for the entire award (that is, over the requisite service period of the last separately vesting portion of the award), ensuring that the amount of compensation cost recognized at any date at least equals the portion of the grant-date value of the award that is vested at that date. The fair value of the Performance Awards is estimated using a Monte Carlo simulation at the grant date. The significant inputs used to calculate the fair value of these awards include (i) the price per our common units at the grant date and the beginning of the performance period, (ii) a compounded risk-free interest rate, (iii) our compounded dividend yield, (iv) our historical volatility, (v) the volatility and correlations of our peers and (vi) the remaining performance period. We record the expense for each of the tranches of the Performance Awards on a straight-line basis over the period beginning with the grant date and ending with the vesting date of the tranche. Any Performance Awards that do not become earned Performance Awards will terminate, expire and otherwise be forfeited by the participants. The amounts reported in the table above for restricted units and performance units is the grant date fair value for financial reporting purposes under ASC 718 and does not represent the amount actually realized by the executive at vesting, which may be less or more than the amount reported in the table above.

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Outstanding Equity Awards at March 31, 2018

The following table summarizes the number of unvested Service Awards and Performance Awards outstanding and their fair values at March 31, 2018:

	Service Awards		Performance Awards	
Name	Number of Units that Have Not Yet Vested (#)(1)	Market Value of Units that Have Not Yet Vested ($)(2)	Number of Units that Have Not Yet Vested (#)(3)	Market Value of Units that Have Not Yet Vested ($)(2)
H. Michael Krimbill	200,000	2,200,000	200,000	2,200,000
Robert W. Karlovich III	62,500	687,500	75,000	825,000
Vincent J. Osterman	50,000	550,000	60,000	660,000
Lawrence J. Thuillier	25,000	275,000	30,000	330,000
Kurston P. McMurray	37,500	412,500	45,000	495,000

(1) Reflects Service Awards that have not vested and are held by each named executive officer.

(2) Calculated based on the closing market price of our common units at March 31, 2018 of $11.00. No adjustments were made to reflect the fact that the restricted units are not entitled to distributions during the vesting period.

(3) Reflects the target number of Performance Awards granted to each named executive officer that have not vested. Vesting of the Performance Awards is contingent upon our relative TUR as measured against the performance peer group and satisfaction of a continued service requirement.

2018 Units Vested

During fiscal year 2018, certain of the restricted Service Awards vested. The following table summarizes the value of the awards on the vesting date which was calculated based of the closing market price per common unit on the vesting dates.

	Service Awards	
Name	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($)
H. Michael Krimbill (1)	100,000	1,357,500
Robert W. Karlovich III (2)	37,500	504,094
Vincent J. Osterman (3)	30,000	403,275
Lawrence J. Thuillier (4)	25,149	331,646
Kurston P. McMurray (5)	22,500	302,456

(1) Mr. Krimbill vested in 100,000 Service Awards on July 10, 2017.

(2) Mr. Karlovich vested in 25,000 and 12,500 Service Awards on July 10, 2017 and February 13, 2018, respectively.

(3) Mr. Osterman vested in 20,000 and 10,000 Service Awards on July 10, 2017 and February 13, 2018, respectively.

(4) Mr. Thuillier vested in 10,000, 10,149 and 5,000 Service Awards on July 10, 2017, November 10, 2017 and February 13, 2018, respectively.

(5) Mr. McMurray vested in 15,000 and 7,500 Service Awards on July 10, 2017 and February 13, 2018, respectively.

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

Name	Number of Units Issued	Number of Units Withheld	Total
Robert W. Karlovich	21,343	16,157	37,500
Vincent J. Osterman	16,950	13,050	30,000
Lawrence J. Thuillier	14,779	10,370	25,149
Kurston P. McMurray	12,778	9,722	22,500

Potential Payments Upon Termination or Change in Control

We do not provide any severance or change of control benefits to our named executive officers, other than Mr. McMurray, who is entitled to receive severance benefits for certain types of terminations (as described in more detail above under the heading, "Employment Agreement with Mr. McMurray"). In the event that Mr. McMurray's employment had been terminated as of March 31, 2018 by the Partnership without "cause" or due to a "constructive discharge," Mr. McMurray would have been entitled to receive the following amounts:

Cash Severance	Value of Guaranteed Unit Awards	Target Annual Bonus	Total
$300,000	$ 495,000	$300,000	$1,095,000

The board of directors has the option to accelerate the vesting of the restricted units in the event of a change in control of the Partnership, although it is not under any obligation to do so. If the board of directors were to exercise its discretion to accelerate the vesting of restricted units upon a change in control, the value of such units would be the same as reported in the "Outstanding Equity Awards at March 31, 2018" table above (in the "Market Value of Units that Have Not Yet Vested" columns).

Pay Ratio Disclosure

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information regarding the ratio of the annual total compensation of our Chief Executive Officer, Mr. Krimbill, to the median of the annual total compensation of our employees for our last fiscal year.

For the year ended March 31, 2018:

- The median of the annual total compensation of all employees (other than the Chief Executive Officer) was $38,798; and
- The annual total compensation of Mr. Krimbill, as reported in the Summary Compensation Table above, was $360,891.

Based on the information for the year ended March 31, 2018, the ratio of the annual total compensation of our Chief Executive Officer to the annual total compensation of our median employee was approximately 9 to 1.

During the year ended March 31, 2018, Mr. Krimbill did not receive any Service Award or Performance Unit grants. If Mr. Krimbill had received a grant of Service Awards and Performance units on January 10, 2018 with the other named executive officers and in the amount comparable to previous grants, Mr. Krimbill's annual total compensation would have been $3,206,053 and the ratio of the annual total compensation of our Chief Executive Officer to the annual total compensation of our median employee would have been approximately 83 to 1.

To determine our median employee, we identified each individual employed by us on January 1, 2018, our determination date. As of that date, we had 2,761 employees located in two countries. We identified the median employee by examining only base pay plus overtime for the period from January 1, 2017 through December 31, 2017. We included all employees, with the exception of three employees that work in Canada, whether employed on a full-time or part-time basis, and did not make any estimates, assumptions or adjustments to any base pay plus overtime amounts. After identifying the median employee, we calculated the annual total compensation for the median employee using the same methodology we use to calculate total annual compensation for our named executive officers, as set forth in the Summary Compensation Table above.

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This pay ratio is a reasonable estimate calculated in a manner consistent with SEC rules based on our payroll and employment records and the methodology described above. The SEC rules for identifying the median employee and calculating the pay ratio based on that employee's annual total compensation allow companies to adopt a variety of methodologies, to apply certain exclusions, and to make reasonable estimates and assumptions that reflect their compensation practices. As such, the pay ratio reported by other companies may not be comparable to the pay ratio reported above, as other companies may have different employment and compensation practices and may utilize different methodologies, exclusions, estimates and assumptions in calculating their own pay ratios.

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 chairmen of the audit and compensation committees; and
- an annual retainer of $5,000 for each member of the audit and compensation committees other than the chairman.

Special committees are convened by the board of directors from time to time to review specific transactions. Compensation paid to the members of these committees varies depending on the transaction and the expected time commitment of the committee members.

In addition, each director who is not an officer or an employee of our general partner has been granted awards of restricted units. In January 2018, such directors were granted 8,000 restricted units that vest in tranches of 4,000 units on each of February 11, 2020 and November 10, 2020.

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 2018

The following table summarizes the compensation earned during fiscal year 2018 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	80,000	94,093	174,093
Stephen L. Cropper	75,000	94,093	169,093
Bryan K. Guderian	80,000	94,093	174,093
James C. Kneale	90,000	94,093	184,093

During the fiscal year ended March 31, 2018, Mr. Collingsworth, Mr. Guderian and Mr. Kneale were all paid $15,000 for being part of the conflicts committee. The amount is included in the fees earned in the table above.

On July 10, 2017, a tranche of 8,000 units vested for each of these directors. On February 13, 2018, 4,000 units vested for Mr. Kneale.

As of March 31, 2018, Mr. Collingsworth, Mr. Cropper and Mr. Guderian each has 24,000 unvested restricted units, while Mr. Kneale has 20,000 unvested restricted units.

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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, 2018 of our common units by:

- each person or group of persons known by us to be a beneficial owner of more than 5% of our outstanding common units;
- each director of our general partner;
- each named executive officer of our general partner; and
- all directors and executive officers of our general partner as a group.

Beneficial Owners	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (1)	
5% or greater unitholders (other than officers and directors):			
ALPS Advisors, Inc. (2)	17,894,258	14.72	%
OppenheimerFunds, Inc. (3)	15,526,215	12.77	%
Harvest Fund Advisors LLC (4)	9,289,135	7.64	%
Directors and named executive officers:			
Shawn W. Coady (5)	2,558,195	2.10	%
James M. Collingsworth (6)	74,750	*	
Stephen L. Cropper (7)	43,000	*	
Bryan K. Guderian	40,500	*	
Robert W. Karlovich III (8)	45,663	*	
James C. Kneale (9)	44,000	*	
H. Michael Krimbill (10)	2,232,820	1.83	%
Kurston P. McMurray (11)	20,575	*	
Vincent J. Osterman (12)	3,983,730	3.28	%
Jared Parker	—	*	
John T. Raymond (13)	176,634	*	
L. John Schaufele IV	—	*	
Lawrence J. Thuillier (14)	19,779	*	
All directors and executive officers as a group (13 persons) (15)	9,239,646	7.60	%

* Less than 1.0%

(1) Based on 121,568,058 common units outstanding at May 25, 2018.

(2) The mailing address for ALPS Advisors, Inc. is 1290 Broadway, Suite 1100, Denver, CO 80203. ALPS Advisors, Inc. reported shared voting and dispositive power with respect to all common units beneficially owned. This information related to ALPS Advisors, Inc. is based upon its Schedule 13G/A filed with the SEC on February 6, 2018.

(3) The mailing address for OppenheimerFunds, Inc. is 225 Liberty Street, New York, NY 10281. OppenheimerFunds, Inc. reported shared voting and dispositive power with respect to all common units beneficially owned. This information related to OppenheimerFunds, Inc. is based upon its Schedule 13G/A filed with the SEC on February 5, 2018.

(4) The mailing address for Harvest Fund Advisors LLC is 100 W. Lancaster, Suite 200, Wayne, PA 19087. Harvest Fund Advisors LLC reported shared voting and dispositive power with respect to all common units beneficially owned. This information related to Harvest Fund Advisors LLC is based upon its Schedule 13G filed with the SEC on April 3, 2018.

(5) Dr. Coady owns 78,304 of these common units, which includes 20,000 units that will vest on July 9, 2018, and does not include 20,000 unvested units which were reported on Dr. Coady's Form 4 which will vest on July 8, 2019. SWC Family Partnership LP owns 2,320,391 of these common units. SWC Family Partnership LP is solely owned by SWC General Partner, LLC, of which Dr. Coady is the sole member. Dr. Coady may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. The 2012 Shawn W. Coady Irrevocable Insurance Trust, which was established for the benefit of Shawn W. Coady's children, owns 135,000 of these common units. Dr. Coady may be deemed to have

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sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. The Tara Nicole Coady Trust II, of which the reporting person is the trustee, owns 12,250 common units. The Colleen Blair Coady Trust, of which the reporting person is the trustee, owns 12,250 common units. Dr. Coady also owns a 12.27% interest in our general partner through Coady Enterprises, LLC, of which he owns 100% of the membership interests.

(6) Mr. Collingsworth owns 70,500 of these common units. Mr. Collingsworth holds 2,000 of these common units jointly with his spouse, Cindy Collingsworth. Cindy Collingsworth and her sister jointly own 2,250 of these common units.

(7) Mr. Cropper owns 18,000 of these common units. The Donna L. Cropper Living Trust, of which Mr. Cropper and his spouse, Donna L. Cropper, are the trustees, owns 25,000 of these common units.

(8) Does not include 12,500 unvested units that will vest on November 13, 2018, 12,500 unvested units that will vest on February 12, 2019, 12,500 unvested units that will vest on November 13, 2019, 12,500 unvested units that will vest on February 11, 2020 and 12,500 unvested units that will vest on November 10, 2020.

(9) Units are held in The Suzanne and Jim Kneale Living Trust, of whom Mr. Kneale and his wife are trustees.

(10) Mr. Krimbill owns 724,417 of these common units, which includes 100,000 units that will vest on July 9, 2018, but does not include 100,000 unvested units that will vest on July 8, 2019. All of the unvested units noted above were reported on Mr. Krimbill’s Form 4. 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 also owns 240,000 of these common units. Krimbill Enterprises LP is controlled by H. Michael Krimbill via his ownership of its general partner, Krimbill Holding Company. H. Michael Krimbill may be deemed to have sole voting and investment power over these units, but disclaims such beneficial ownership except to the extent of his pecuniary interest therein. KrimGP2010 LLC owns 363,555 of these common units. KrimGP2010 LLC is solely owned by H. Michael Krimbill. H. Michael Krimbill may be deemed to have sole voting and investment power over these units. H. Michael Krimbill also owns a 14.81% interest in our general partner through KrimGP2010, LLC, of which he owns 100% of the membership interests and Krimbill Capital Group, LLC, which is owned 100% by the H. Michael Krimbill Revocable Trust, of which Mr. Krimbill is the trustee.

(11) Does not include 7,500 unvested units that will vest on November 13, 2018, 7,500 unvested units that will vest on February 12, 2019, 7,500 unvested units that will vest on November 13, 2019, 7,500 unvested units that will vest on February 11, 2020 and 7,500 unvested units that will vest on November 10, 2020.

(12) Mr. Osterman owns 129,093 of these common units which does not include 10,000 unvested units that will vest on November 13, 2018, 10,000 unvested units that will vest on February 12, 2019, 10,000 unvested units that will vest on November 13, 2019, 10,000 unvested units that will vest on February 11, 2020 and 10,000 unvested units that will vest on November 10, 2020 that were reported on Mr. Osterman’s most recent Form 4. The remaining common units are owned by AO Energy, Inc. (110,587 common units), E. Osterman, Inc. (394,350 common units), E. Osterman Gas Services, Inc. (301,700 common units), E. Osterman Propane, Inc. (669,300 common units), Milford Propane, Inc. (559,784 common units), Osterman Family Foundation (122,016 common units), Osterman Propane, Inc. (1,445,850 common units), Propane Gas, Inc. (36,450 common units) and Saveway Propane Gas Service, Inc. (214,600 common units). Each of these holding entities may be deemed to have sole voting and investment power over its own common units and Propane Gas, LLC, as sole shareholder of Propane Gas, Inc., may be deemed to have sole voting and investment power over those common units. Vincent J. Osterman is a director, executive officer and shareholder or member of each of these entities and may be deemed to have sole voting and investment power over 798,393 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 1.65% interest in our general partner through VE Properties XI LLC.

(13) EMG NGL HC, LLC owns all of the 176,634 common units. John T. Raymond is the Chief Executive Officer and Managing Partner of NGP MR GP LLC, the general partner of NGP MR, LP, the general partner of NGP Midstream & Resources, LLC, a member holding a majority interest in EMG NGL HC LLC. John T. Raymond

may be deemed to have shared voting and investment power over these units, but disclaims beneficial ownership except to the extent of his pecuniary interest therein. EMG I NGL GP Holdings, LLC, an affiliate of EMG NGL HC LLC, owns a 5.73% interest in our general partner. EMG II NGL GP Holdings, LLC, an affiliate of EMG NGL HC LLC, owns a 5.36% interest in our general partner.

(14) Does not include 5,000 unvested units that will vest on November 13, 2018, 5,000 unvested units that will vest on February 12, 2019, 5,000 unvested units that will vest on November 13, 2019, 5,000 unvested units that will vest on February 11, 2020 and 5,000 unvested units that will vest on November 10, 2020.

(15) The directors and executive officers of our general partner also collectively own a 48.11% interest in our general partner.

Unless otherwise noted, each of the individuals listed above is believed to have sole voting and investment power with respect to the units beneficially held by them. The mailing address for each of the officers and directors of our general partner listed above is 6120 South Yale Avenue, Suite 805, Tulsa, Oklahoma 74136.

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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, 2018.

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)	2,278,875	—	1,277,668
Total	2,278,875	—	1,277,668

(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 51,839,254 common units, representing an aggregate 42.68% 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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Operation Stage

Distributions of available cash to our directors, officers, and greater than 5% owners and our general partner	We generally make cash distributions 99.9% to our unitholders pro rata, including our directors, officers, and greater than 5% owners as the holders of an aggregate 51,839,254 common units, and 0.1% to our general partner. In addition, when distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner is entitled to increasing percentages of the distributions, up to 48.1% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the same quarterly distribution on all of our outstanding units for four quarters that we paid in May 2018 ($0.39 per unit), our general partner would receive an annual distribution of $0.3 million on its general partner interest and incentive distribution rights, and our directors, officers, and greater than 5% owners would receive an aggregate annual distribution of $80.9 million on their common units. If our general partner elects to reset the target distribution levels, it will be entitled to receive common units and to maintain its general partner interest.
Payments to our general partner and its affiliates	Our general partner and its affiliates do not receive any management fee or other compensation for the management of our business and affairs, but they are reimbursed for all expenses that they incur on our behalf, including general and administrative expenses. As the sole purpose of the general partner is to act as our general partner, substantially all of the expenses of our general partner are incurred on our behalf and reimbursed by us or our subsidiaries. Our general partner determines the amount of these expenses.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its IDRs will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Transactions With Related Persons

SemGroup

SemGroup holds an 11.78% ownership interest in our general partner. We sell product to and purchase product from SemGroup, and these transactions are included within revenues and cost of sales, respectively, in our consolidated statements of operations (certain of the purchases and sales that were entered into in contemplation of each other are recorded on a net basis within revenues in our consolidated statement of operations). We also lease crude oil storage from SemGroup. The following table summarizes transactions with SemGroup for the year ended March 31, 2018 (in thousands):

Sales to SemGroup	$24,865
Purchases from SemGroup	$29,895

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WPX

Bryan K. Guderian is a member of our board of directors and an executive officer of WPX. We purchase crude oil from and sell crude oil to WPX (certain of the purchases and sales that were entered into in contemplation of each other are recorded on a net basis within revenues in our consolidated statement of operations). We also treat and dispose of wastewater and solids received from WPX. The following table summarizes transactions with WPX for the year ended March 31, 2018 (in thousands):

Sales to WPX	$4,231
Purchases from WPX	$162,773

Other Transactions

We purchase goods and services from certain entities that are partially owned by our executive officers. The following table summarizes these transactions for the year ended March 31, 2018:

Entity	Nature of Purchases	Amount Purchased	Ownership Interest in Entity
		(in thousands)	
Shawn W. Coady			
Hicks Motor Sales	Vehicle purchases	$ 772	50 %
Vincent J. Osterman			
VE Properties III, LLC	Office space rental	$ 153	100 %
H. Michael Krimbill			
Pinnacle Aviation 2007, LLC	Aircraft rental	$ 102	50 %
H. Michael Krimbill			
KAIR2014 LLC	Aircraft rental	$ 76	50 %

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 received salary payments during the year ended March 31, 2018 of $200,000. Timothy Osterman was also eligible to participate in the Partnership's 401(k) plan, and he received $7,000 of employer matching contributions during the year ended March 31, 2018.

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 owned by the parties to the Registration Rights Agreement. In connection with our IPO, we granted registration rights to the NGL Energy LP Investor Group, and subsequently, we have granted registration rights in connection with several acquisitions. We will not be required to register such common units if an exemption from the registration requirements of the Securities Act is available with respect to the number of common units desired to be sold. Subject to limitations specified in the Registration Rights Agreement, the registration rights of the registration rights parties include the following:

- Demand Registration Rights. Certain registration rights parties deemed "Significant Holders" under the agreement may, to the extent that they continue to own more than 4% of our common units, require us to file a registration statement with the SEC registering the offer and sale of a specified number of common units, subject to limitations on the number of requests for registration that can be made in any twelve-month period as well as customary cutbacks at the discretion of the underwriters relating to a potential offering. All other registration rights parties are entitled to notice of a Significant Holder's exercise of its demand registration rights and may include their common units in such registration. We can only be required to file a total of nine registration statements upon the Significant Holders' exercise of these demand registration rights and are only required to effect demand registration if the aggregate proposed offering price to the public is at least $10.0 million.

Piggyback Registration Rights. If we propose to file a registration statement under the Securities Act to register our common units, the registration rights parties are entitled to notice of such registration and have the right to include their common units in the registration, subject to limitations that the underwriters relating to a potential

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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 person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to:

- whether there is an appropriate business justification for the transaction;
- the benefits that accrue to the Partnership as a result of the transaction;
- the terms available to unrelated third parties entering into similar transactions;
- the impact of the transaction on a director’s independence (in the event the related party is a director, an immediate family member of a director or an entity in which a director is a partner, shareholder or executive officer);
- the availability of other sources for comparable products or services;
- whether it is a single transaction or a series of ongoing, related transactions; and
- whether entering into the transaction would be consistent with the Code of Business Conduct and Ethics.

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, see Part III, Item 10–“Directors, Executive Officers and Corporate Governance–Board of Directors of our General Partner.”

Item 14. Principal Accounting Fees and Services

We have engaged Grant Thornton LLP as our independent registered public accounting firm. The following table summarizes fees we have paid Grant Thornton LLP to audit our annual consolidated financial statements and for other services for the periods indicated:

	March 31,	
	2018	2017
Audit fees (1)	$2,507,000	$2,646,096
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$2,507,000	$2,646,096

(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.

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Audit Committee Approval of Audit and Non-Audit Services

The audit committee of the board of directors of our general partner has adopted a pre-approval policy with respect to services which may be performed by Grant Thornton LLP. This policy lists specific audit-related services as well as any other services that Grant Thornton LLP is authorized to perform and sets out specific dollar limits for each specific service, which may not be exceeded without additional audit committee authorization. The audit committee receives quarterly reports on the status of expenditures pursuant to the pre-approval policy. The audit committee reviews the policy at least annually in order to approve services and limits for the current year. Any service that is not clearly enumerated in the policy must receive specific pre-approval by the audit committee prior to engagement.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report:

1. Financial Statements. See the accompanying Index to Financial Statements.
2. Financial Statement Schedules. All schedules have been omitted because they are either not applicable, not required or the information required in such schedules appears in the financial statements or the related notes.
3. Exhibits.

Exhibit Number	Description
2.1	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, as the Representative, OWL Pearsall SWD, LLC, OWL Pearsall Holdings, LLC, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.2	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, as the Representative, OWL Karnes SWD, LLC, OWL Karnes Holdings, LLC, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.3	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, OWL Cotulla SWD, LLC, Terry Bailey, as trustee of the PJB Irrevocable Trust, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.4	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, OWL Nixon SWD, LLC, Terry Bailey, as trustee of the PJB Irrevocable Trust, NGL Energy Partners, LP and High Sierra Water-Eagle Ford, LLC (incorporated by reference to Exhibit 2.4 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.5	LLC Interest Transfer Agreement, dated as of August 1, 2013, by and among Oilfield Water Lines, LP, HR OWL, LLC, OWL Operating, LLC, Lotus Oilfield Services, L.L.C., OWL Lotus, LLC, NGL Energy Partners, LP, High Sierra Water-Eagle Ford, LLC and High Sierra Transportation, LLC (incorporated by reference to Exhibit 2.5 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
2.6	Equity Interest Purchase Agreement, dated November 5, 2013, by and among NGL Energy Partners LP, High Sierra Energy, LP, Gavilon, LLC and Gavilon Energy Intermediate, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 5, 2013)
3.1	Certificate of Limited Partnership of NGL Energy Partners LP (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (File No. 333-172186) filed with the SEC 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 with the SEC on April 15, 2011)
3.3	Fourth Amended and Restated Agreement of Limited Partnership of NGL Energy Partners LP, dated as of June 13, 2017 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 13, 2017)
3.4	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 with the SEC on April 15, 2011)
3.5	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 with the SEC on April 15, 2011)
3.6	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 with the SEC on February 28, 2013)

3.7	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)
3.8	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)
3.9	Amendment No. 3 to Third Amended and Restated Limited Liability Company Agreement of NGL Energy Holdings LLC, dated as of June 24, 2016 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 28, 2016)
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 with the SEC 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 with the SEC on November 4, 2011)

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Exhibit Number	Description
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 with the SEC on January 9, 2012)
4.4	Amendment No. 3 and Joinder to First Amended and Restated Registration Rights Agreement, dated May 1, 2012, by and between NGL Energy Holdings LLC and Downeast Energy Corp. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on May 4, 2012)
4.5	Amendment No. 4 and Joinder to First Amended and Restated Registration Rights Agreement, dated June 19, 2012, by and between NGL Energy Holdings LLC and NGP M&R HS LP LLC (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on June 25, 2012)
4.6	Amendment No. 5 and Joinder to First Amended and Restated Registration Rights Agreement, dated October 1, 2012, by and between NGL Energy Holdings LLC and Enstone, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on October 3, 2012)
4.7	Amendment No. 6 and Joinder to First Amended and Restated Registration Rights Agreement, dated November 13, 2012, by and between NGL Energy Holdings LLC and Gerald L. Jensen, Thrift Opportunity Holdings, LP, Jenco Petroleum Corporation, Caritas Trust, Animosus Trust and Nitor Trust (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on November 19, 2012)
4.8	Amendment No. 7 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of August 1, 2013, by and among NGL Energy Holdings LLC, Oilfield Water Lines, LP and Terry G. Bailey (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on August 7, 2013)
4.9	Amendment No. 8 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of February 17, 2015, by and among NGL Energy Holdings LLC and Magnum NGL Holdco LLC (incorporated by reference to Exhibit 4.9 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.10	Amendment No. 9 and Joinder to First Amended and Restated Registration Rights Agreement, dated as of February 25, 2016, by and among NGL Energy Holdings LLC and Magnum NGL Holdco LLC (incorporated by reference to Exhibit 4.10 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2016 filed with the SEC on May 31, 2016)
4.11	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)
4.12	Forms of 6.875% Senior Notes due 2021 (incorporated by reference to Exhibit 4.2 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 October 16, 2013)
4.13	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)
4.14	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)
4.15	Second Supplemental Indenture, dated as of April 22, 2014, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiary party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.20 to the Annual Report on Form 10-K (File

	No. 001-35172) for the year ended March 31, 2014 filed with the SEC on May 30, 2014)
4.16	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)
4.17	Fourth Supplemental Indenture, dated as of December 1, 2014, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.24 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.18	Fifth Supplemental Indenture, dated as of February 17, 2015, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.25 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.19	Sixth Supplemental Indenture, dated as of August 21, 2015, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended September 30, 2015 filed with the SEC on November 9, 2015)
4.20	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)

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Exhibit Number	Description
4.21	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)
4.22	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)
4.23	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)
4.24	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)
4.25	Second Supplemental Indenture, dated as of December 1, 2014, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.32 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.26	Third Supplemental Indenture, dated as of February 17, 2015, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.33 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
4.27	Fourth Supplemental Indenture, dated as of August 21, 2015, among NGL Energy Partners LP, NGL Energy Finance Corp., the Guaranteeing Subsidiaries party thereto, the Guarantors party thereto and U.S. Bank National Association, as Trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended September 30, 2015 filed with the SEC on November 9, 2015)
4.28	Registration Rights Agreement, dated May 11, 2016, by and among NGL Energy Partners LP and Highstar NGL Prism/IV-A Interco LLC and Highstar NGL Main Interco 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 June 28, 2016)
4.29	Amendment to Registration Rights Agreement, dated June 24, 2016, by and among NGL Energy Partners LP and Highstar NGL Prism/IV-A Interco LLC, Highstar NGL Main Interco LLC and NGL CIV A, 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 28, 2016)
4.30	Indenture, dated as of October 24, 2016, 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 24, 2016)
4.31	Forms of 7.5% Senior Notes due 2023 (incorporated by reference to Exhibit 4.2 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 October 24, 2016)
4.32	Registration Rights Agreement, dated as of October 24, 2016, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the guarantors listed therein on Exhibit A and Barclays Capital 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 October 24, 2016)
4.33	Indenture, dated as of February 22, 2017, 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 February 22, 2017)
4.34	Forms of 6.125% Senior Notes due 2025 (incorporated by reference to Exhibit 4.2 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 February 22, 2017)

4.35	Registration Rights Agreement, dated as of February 22, 2017, by and among NGL Energy Partners LP, NGL Energy Finance Corp., the guarantors listed therein on Exhibit A and RBC Capital Markets, LLC and Deutsche Bank Securities Inc., as representatives 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 February 22, 2017)
4.36	Amended and Restated Guaranty Agreement, dated as of March 31, 2017 and effective as of December 31, 2016, among NGL Energy Partners LP and the purchasers named therein (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended June 30, 2017 filed with the SEC on August 4, 2017)
10.1	Amended and Restated Credit Agreement, dated as of February 14, 2017, by and among NGL Energy Partners LP, NGL Energy Operating LLC, the subsidiary guarantors party thereto, Deutsche Bank Trust Company Americas, Deutsche Bank AG, New York Branch, 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 February 15, 2017)
10.2	Amendment No. 1 to Amended and Restated Credit Agreement, dated as of March 31, 2017, among the NGL Energy Partners LP, NGL Energy Operating LLC, the other 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 April 5, 2017)
10.3	Amendment No. 2 to Amended and Restated Credit Agreement, dated as of June 2, 2017, among the NGL Energy Partners LP, NGL Energy Operating LLC, the other 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 5, 2017)

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Exhibit Number	Description
10.4	Amendment No. 3 to Amended and Restated Credit Agreement, dated as of February 5, 2018, among NGL Energy Partners LP, NGL Energy Operating LLC, the other 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 Quarterly Report on Form 10-Q (File No. 001-35172) for the quarter ended December 31, 2017 filed with the SEC on February 9, 2018)
10.5	Amendment No. 4 to Amended and Restated Credit Agreement, dated as of March 6, 2018, among the Partnership, NGL Energy Operating LLC, the other 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 (Fie No. 001-35172) filed with the SEC on March 8, 2018)
10.6*	Amendment No. 5 to Amended and Restated Credit Agreement, dated as of May 24, 2018, among the Partnership, NGL Energy Operating LLC, the other subsidiary borrowers party thereto, Deutsche Bank Trust Company Americas, and the other financial institutions party thereto
10.7	Class A Convertible Preferred Unit and Warrant Purchase Agreement, dated as of April 21, 2016, by and among NGL Energy Partners LP, Highstar NGL Prism/IV-A Interco LLC and Highstar NGL Main Interco LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on April 27, 2016)
10.8	Amendment to Class A Convertible Preferred Unit and Warrant Purchase Agreement, dated as of June 23, 2016, by and among NGL Energy Partners LP and Highstar NGL Prism/IV-A Interco LLC, Highstar NGL Main Interco LLC and NGL CIV A, LLC (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 28, 2016)
10.9	Form of Warrant (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K (File No. 001-35172) filed on June 28, 2016)
10.10	Waiver of Class A Preemptive Rights Holders and Option to Purchase Class C Preferred Units, dated June 6, 2017, by and among NGL Energy Partners and Highstar NGL Prism/IV-A Interco LLC, Highstar NGL Main Interco LLC, NGL CIV A, LLC and NGL Prism/IV-A Blocker, LLC (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 9, 2017)
10.11	Common Unit Purchase Agreement, dated November 5, 2013, by and among NGL Energy Partners LP and the purchasers listed on Schedule A thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K (File No. 001-35172) filed with the SEC on December 5, 2013)
10.12+	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 with the SEC on April 15, 2011)
10.13+	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 with the SEC on May 17, 2011)
10.14+	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)
10.15+	NGL Performance Unit Program (incorporated by reference to Exhibit 10.18 to the Annual Report on Form 10-K (File No. 001-35172) for the year ended March 31, 2015 filed with the SEC on June 1, 2015)
12.1*	Computation of ratios of earnings to fixed charges and combined fixed charges and preferred unit distributions
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, 2018 and 2017, (ii) Consolidated Statements of Operations for the years ended March 31, 2018, 2017, and 2016, (iii) Consolidated Statements of Comprehensive (Loss) Income for the years ended March 31, 2018, 2017, and 2016, (iv) Consolidated Statements of Changes in Equity for the years ended March 31, 2018, 2017, and 2016, (v) Consolidated Statements of Cash Flows for the years ended March 31, 2018, 2017, and 2016, and (vi) Notes to Consolidated Financial Statements.

+ Management contracts or compensatory plans or arrangements.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on May 30, 2018.

NGL ENERGY PARTNERS LP

By: NGL Energy Holdings LLC, its general partner

By: /s/ H. Michael Krimbill
H. Michael Krimbill
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ H. Michael Krimbill H. Michael Krimbill	Chief Executive Officer and Director (Principal Executive Officer)	May 30, 2018
/s/ Robert W. Karlovich III Robert W. Karlovich III	Chief Financial Officer (Principal Financial Officer)	May 30, 2018
/s/ Lawrence J. Thuillier Lawrence J. Thuillier	Chief Accounting Officer (Principal Accounting Officer)	May 30, 2018
Shawn W. Coady	Director	May 30, 2018
James M. Collingsworth	Director	May 30, 2018
Stephen L. Cropper	Director	May 30, 2018
/s/ Bryan K. Guderian Bryan K. Guderian	Director	May 30, 2018
/s/ James C. Kneale James C. Kneale	Director	May 30, 2018
/s/ Vincent J. Osterman Vincent J. Osterman	Director	May 30, 2018
/s/ Jared Parker Jared Parker	Director	May 30, 2018
/s/ John T. Raymond John T. Raymond	Director	May 30, 2018

/s/ L. John Schaufele IV L. John Schaufele IV	Director	May 30, 2018

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NGL ENERGY PARTNERS LP

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
NGL Energy Partners LP

Opinion on the financial statements
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, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended March 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of March 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended March 31, 2018, 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) ("PCAOB"), the Partnership's internal control over financial reporting as of March 31, 2018, 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 May 30, 2018 expressed an unqualified opinion.

Basis for opinion
These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Partnership's auditor since 2010.

Tulsa, Oklahoma
May 30, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
NGL Energy Partners LP

Opinion on internal control over financial reporting

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, 2018, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of March 31, 2018, 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) ("PCAOB"), the consolidated financial statements of the Partnership as of and for the year ended March 31, 2018, and our report dated May 30, 2018 expressed an unqualified opinion on those financial statements.

Basis for opinion

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. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
May 30, 2018

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NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Consolidated Balance Sheets
(in Thousands, except unit amounts)

	March 31, 2018	2017
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$26,207	$12,264
Accounts receivable-trade, net of allowance for doubtful accounts of $5,347 and $5,234, respectively	1,072,688	800,607
Accounts receivable-affiliates	4,772	6,711
Inventories	564,553	561,432
Prepaid expenses and other current assets	131,538	103,193
Total current assets	1,799,758	1,484,207
PROPERTY, PLANT AND EQUIPMENT, net of accumulated depreciation of $443,066 and $375,594, respectively	1,719,947	1,790,273
GOODWILL	1,312,558	1,451,716
INTANGIBLE ASSETS, net of accumulated amortization of $486,456 and $414,605, respectively	1,054,482	1,163,956
INVESTMENTS IN UNCONSOLIDATED ENTITIES	17,236	187,423
LOAN RECEIVABLE-AFFILIATE	1,200	3,200
OTHER NONCURRENT ASSETS	245,941	239,604
Total assets	$6,151,122	$6,320,379
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable-trade	$860,629	$658,021
Accounts payable-affiliates	1,254	7,918
Accrued expenses and other payables	230,087	207,125
Advance payments received from customers	21,216	35,944
Current maturities of long-term debt	3,196	29,590
Total current liabilities	1,116,382	938,598
LONG-TERM DEBT, net of debt issuance costs of $20,645 and $33,458, respectively, and current maturities	2,682,628	2,963,483
OTHER NONCURRENT LIABILITIES	173,514	184,534
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
CLASS A 10.75% CONVERTIBLE PREFERRED UNITS, 19,942,169 and 19,942,169 preferred units issued and outstanding, respectively	82,576	63,890
REDEEMABLE NONCONTROLLING INTEREST	9,927	3,072
EQUITY:		
General partner, representing a 0.1% interest, 121,594 and 120,300 notional units, respectively	(50,819)	(50,529)
Limited partners, representing a 99.9% interest, 121,472,725 and 120,179,407 common units issued and outstanding, respectively	1,852,495	2,192,413
Class B preferred limited partners, 8,400,000 and 0 preferred units issued and outstanding, respectively	202,731	—
Accumulated other comprehensive loss	(1,815)	(1,828)
Noncontrolling interests	83,503	26,746

Total equity	2,086,095	2,166,802
Total liabilities and equity	$6,151,122	$6,320,379

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
(in Thousands, except unit and per unit amounts)

	Year Ended March 31,		
	2018	2017	2016
REVENUES:			
Crude Oil Logistics	$2,260,075	$1,666,884	$3,217,079
Water Solutions	229,139	159,601	185,001
Liquids	2,070,015	1,439,088	1,194,479
Retail Propane	521,392	413,109	352,977
Refined Products and Renewables	12,200,923	9,342,702	6,792,112
Other	1,174	844	462
Total Revenues	17,282,718	13,022,228	11,742,110
COST OF SALES:			
Crude Oil Logistics	2,113,747	1,572,015	3,111,717
Water Solutions	19,345	4,068	(7,336)
Liquids	1,982,552	1,334,116	1,037,118
Retail Propane	269,367	191,589	156,757
Refined Products and Renewables	12,150,497	9,219,721	6,540,599
Other	530	400	182
Total Cost of Sales	16,536,038	12,321,909	10,839,037
OPERATING COSTS AND EXPENSES:			
Operating	330,857	307,925	401,118
General and administrative	109,451	116,566	139,541
Depreciation and amortization	252,712	223,205	228,924
(Gain) loss on disposal or impairment of assets, net	(105,313)	(209,177)	320,766
Revaluation of liabilities	20,716	6,717	(82,673)
Operating Income (Loss)	138,257	255,083	(104,603)
OTHER INCOME (EXPENSE):			
Equity in earnings of unconsolidated entities	7,964	3,084	16,121
Revaluation of investments	—	(14,365)	—
Interest expense	(199,570)	(150,478)	(133,089)
(Loss) gain on early extinguishment of liabilities, net	(23,201)	24,727	28,532
Other income, net	8,403	27,762	5,575
(Loss) Income Before Income Taxes	(68,147)	145,813	(187,464)
INCOME TAX (EXPENSE) BENEFIT	(1,458)	(1,939)	367
Net (Loss) Income	(69,605)	143,874	(187,097)
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(240)	(6,832)	(11,832)
LESS: NET INCOME ATTRIBUTABLE TO REDEEMABLE NONCONTROLLING INTERESTS	(1,030)	—	—
NET (LOSS) INCOME ATTRIBUTABLE TO NGL ENERGY PARTNERS LP	(70,875)	137,042	(198,929)
LESS: DISTRIBUTIONS TO PREFERRED UNITHOLDERS	(59,697)	(30,142)	—
LESS: NET INCOME ALLOCATED TO GENERAL PARTNER	(5)	(232)	(47,620)
LESS: REPURCHASE OF WARRANTS	(349)	—	—
NET (LOSS) INCOME ALLOCATED TO COMMON UNITHOLDERS	$(130,926)	$106,668	$(246,549)
BASIC (LOSS) INCOME PER COMMON UNIT	$(1.08)	$0.99	$(2.35)
DILUTED (LOSS) INCOME PER COMMON UNIT	$(1.08)	$0.95	$(2.35)

BASIC WEIGHTED AVERAGE COMMON UNITS OUTSTANDING	120,991,340	108,091,486	104,838,886
DILUTED WEIGHTED AVERAGE COMMON UNITS OUTSTANDING	120,991,340	111,850,621	104,838,886

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 (Loss) Income
(in Thousands)

	Year Ended March 31,		
	2018	2017	2016
Net (loss) income	$(69,605)	$143,874	$(187,097)
Other comprehensive income (loss)	13	(1,671)	(48)
Comprehensive (loss) income	$(69,592)	$142,203	$(187,145)

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, 2018, 2017, and 2016
(in Thousands, except unit amounts)

		Limited Partners						
		Class B Preferred		Common				
	General Partner	Units	Amount	Units	Amount	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
BALANCES AT MARCH 31, 2015	$(37,000)	—	$—	103,794,870	$2,183,551	$ (109)	$ 546,990	$2,693,432
Distributions to general and common unit partners (Note 10)	(61,485)	—	—	—	(260,522)	—	—	(322,007)
Distributions to noncontrolling interest owners	—	—	—	—	—	—	(35,720)	(35,720)
Contributions	54	—	—	—	(3,829)	—	15,376	11,601
Business combinations	—	—	—	833,454	19,108	—	9,248	28,356
Equity issued pursuant to incentive compensation plan (Note 10)	—	—	—	1,165,053	33,290	—	—	33,290
Common unit repurchases (Note 10)	—	—	—	(1,623,804)	(17,680)	—	—	(17,680)
Net income (loss)	47,620	—	—	—	(246,549)	—	11,832	(187,097)
Deconsolidation of TLP	—	—	—	—	—	—	(511,291)	(511,291)
Other comprehensive loss	—	—	—	—	—	(48)	—	(48)
TLP equity-based compensation	—	—	—	—	—	—	1,301	1,301
Other	—	—	—	—	(43)	—	(29)	(72)
BALANCES AT MARCH 31, 2016	(50,811)	—	—	104,169,573	1,707,326	(157)	37,707	1,694,065
Distributions to general and common unit partners and preferred unitholders (Note 10)	(287)	—	—	—	(181,294)	—	—	(181,581)

Distributions to noncontrolling interest owners	—	—	—	—	—	—	(3,292)	(3,292)
Contributions	49	—	—	—	(501)	—	1,173	721
Business combinations	—	—	—	218,617	3,940	—	—	3,940
Purchase of noncontrolling interest	—	—	—	—	(215)	—	(12,602)	(12,817)
Equity issued pursuant to incentive compensation plan (Note 10)	—	—	—	2,350,082	68,414	—	—	68,414
Common units issued, net of offering costs (Note 10)	288	—	—	13,441,135	286,848	—	—	287,136
Allocation of value to beneficial conversion feature of Class A convertible preferred units (Note 10)	—	—	—	—	131,534	—	—	131,534
Issuance of warrants, net of offering costs (Note 10)	—	—	—	—	48,550	—	—	48,550
Accretion of beneficial conversion feature of Class A convertible preferred units (Note 10)	—	—	—	—	(8,999)	—	—	(8,999)
Transfer of redeemable noncontrolling interest (Note 2)	—	—	—	—	—	—	(3,072)	(3,072)
Net income	232	—	—	—	136,810	—	6,832	143,874
Other comprehensive loss	—	—	—	—	—	(1,671)	—	(1,671)
BALANCES AT MARCH 31, 2017	(50,529)	—	—	120,179,407	2,192,413	(1,828)	26,746	2,166,802
Distributions to general and common unit partners and preferred	(323)	—	—	—	(229,469)	—	—	(229,792)

unitholders (Note 10)								
Distributions to noncontrolling interest owners	—	—	—	—	—	—	(3,082)	(3,082)
Contributions	—	—	—	—	—	—	23	23
Sawtooth joint venture (Note 15)	—	—	—	—	(16,981)	—	76,214	59,233
Purchase of noncontrolling interest (Note 4)	—	—	—	—	(6,245)	—	(16,638)	(22,883)
Redeemable noncontrolling interest valuation adjustment (Note 2)	—	—	—	—	(5,825)	—	—	(5,825)
Repurchase of warrants (Note 10)	—	—	—	—	(10,549)	—	—	(10,549)
Equity issued pursuant to incentive compensation plan (Note 10)	28	—	—	2,260,011	34,623	—	—	34,651
Common unit repurchases and cancellations (Note 10)	—	—	—	(1,574,346)	(15,817)	—	—	(15,817)
Warrants exercised (Note 10)	—	—	—	607,653	6	—	—	6
Accretion of beneficial conversion feature of Class A convertible preferred units (Note 10)	—	—	—	—	(18,781)	—	—	(18,781)
Issuance of Class B preferred units, net of offering costs (Note 10)	—	8,400,000	202,731	—	—	—	—	202,731
Net income (loss)	5	—	—	—	(70,880)	—	240	(70,635)
Other comprehensive income	—	—	—	—	—	13	—	13
BALANCES AT MARCH 31, 2018	$(50,819)	8,400,000	$202,731	121,472,725	$1,852,495	$ (1,815)	$ 83,503	$2,086,095

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
(in Thousands)

	Year Ended March 31,		
	2018	2017	2016
OPERATING ACTIVITIES:			
Net (loss) income	$(69,605)	$143,874	$(187,097)
Adjustments to reconcile net (loss) income to net cash provided by (used in) operating activities:			
Depreciation and amortization, including amortization of debt issuance costs	269,430	237,795	249,211
Loss (gain) on early extinguishment or revaluation of liabilities, net	43,917	(18,010)	(111,205)
Gain on termination of a storage sublease agreement	—	(16,205)	—
Non-cash equity-based compensation expense	35,241	53,102	51,565
(Gain) loss on disposal or impairment of assets, net	(105,313)	(209,177)	320,766
Provision for doubtful accounts	2,415	1,029	5,628
Net adjustments to fair value of commodity derivatives	116,878	56,356	(103,223)
Equity in earnings of unconsolidated entities	(7,964)	(3,084)	(16,121)
Distributions of earnings from unconsolidated entities	4,632	3,564	17,404
Revaluation of investments	—	14,365	—
Other	765	(5,036)	(5,854)
Changes in operating assets and liabilities, exclusive of acquisitions:			
Accounts receivable-trade and affiliates	(296,851)	(269,425)	505,540
Inventories	(7,708)	(192,190)	74,686
Other current and noncurrent assets	(19,738)	(53,173)	10,572
Accounts payable-trade and affiliates	195,542	239,047	(439,709)
Other current and noncurrent liabilities	(23,999)	(7,072)	(20,668)
Net cash provided by (used in) operating activities	137,642	(24,240)	351,495
INVESTING ACTIVITIES:			
Capital expenditures	(156,214)	(363,871)	(661,885)
Acquisitions, net of cash acquired	(50,417)	(122,832)	(234,652)
Cash flows from settlements of commodity derivatives	(100,654)	(37,442)	105,662
Proceeds from sales of assets	36,590	29,566	8,455
Proceeds from divestitures of businesses and investments	545,495	134,370	343,135
Transaction with an unconsolidated entity (Note 13)	(6,424)	—	—
Investments in unconsolidated entities	(21,465)	(2,105)	(11,431)
Distributions of capital from unconsolidated entities	11,969	9,692	15,792
Loan for natural gas liquids facility	—	—	(3,913)
Repayments on loan for natural gas liquids facility	10,052	8,916	7,618
Loan to affiliate	(2,510)	(3,200)	(15,621)
Repayments on loan to affiliate	4,160	655	1,513
Payment to terminate development agreement	—	(16,875)	—
Net cash provided by (used in) investing activities	270,582	(363,126)	(445,327)
FINANCING ACTIVITIES:			
Proceeds from borrowings under revolving credit facilities	2,434,500	1,700,000	2,602,500
Payments on revolving credit facilities	(2,279,500)	(2,733,500)	(2,133,000)
Issuance of senior unsecured notes	—	1,200,000	—
Repayment and repurchase of senior secured and senior unsecured notes	(486,699)	(21,193)	(43,421)
Proceeds from borrowings under other long-term debt	—	—	53,223
Payments on other long-term debt	(4,713)	(49,786)	(5,087)

Debt issuance costs	(2,700)	(33,558)	(10,237)
Contributions from general partner	—	49	54
Contributions from noncontrolling interest owners, net	23	672	11,547
Distributions to general and common unit partners and preferred unitholders	(225,067)	(181,581)	(322,007)
Distributions to noncontrolling interest owners	(3,082)	(3,292)	(35,720)
Proceeds from sale of preferred units, net of offering costs	202,731	234,975	—
Repurchase of warrants	(10,549)	—	—
Common unit repurchases and cancellations	(15,817)	—	(17,680)
Proceeds from sale of common units, net of offering costs	—	287,136	—
Payments for settlement and early extinguishment of liabilities	(3,408)	(28,468)	—
Taxes paid on behalf of equity incentive plan participants	—	—	(19,395)
Other	—	—	(72)
Net cash (used in) provided by financing activities	(394,281)	371,454	80,705
Net increase (decrease) in cash and cash equivalents	13,943	(15,912)	(13,127)
Cash and cash equivalents, beginning of period	12,264	28,176	41,303
Cash and cash equivalents, end of period	$26,207	$12,264	$28,176
Supplemental cash flow information:			
Cash interest paid	$192,938	$117,912	$117,185
Income taxes paid (net of income tax refunds)	$1,843	$2,022	$2,300
Supplemental non-cash investing and financing activities:			
Distributions declared but not paid to Class B preferred unitholders	$4,725	$—	$—
Accrued capital expenditures	$12,123	$1,758	$1,907
Value of common units issued in business combinations	$—	$3,940	$19,108

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

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements

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 discussed in Note 4. At March 31, 2018, our operations include:

- Our Crude Oil Logistics segment purchases crude oil from producers and transports it to refineries or for resale at pipeline injection stations, storage terminals, barge loading facilities, rail facilities, refineries, and other trade hubs, and provides storage, terminaling, trucking, marine and pipeline transportation services through its owned assets.
- Our Water Solutions segment provides services for the treatment and disposal of wastewater generated from crude oil and natural gas production and for the disposal of solids such as tank bottoms, drilling fluids and drilling muds and performs truck and frac tank washouts. In addition, our Water Solutions segment sells the recovered hydrocarbons that result from performing these services.
- Our Liquids segment supplies natural gas liquids to retailers, wholesalers, refiners, and petrochemical plants throughout the United States and in Canada using its leased underground storage and fleet of leased railcars, markets regionally through its 21 owned terminals throughout the United States, and provides terminaling and storage services at its salt dome storage facility joint venture in Utah. See Note 15 for a discussion of the joint venture of our Sawtooth NGL Caverns, LLC ("Sawtooth") business.
- Our Retail Propane segment sells propane, distillates, equipment and supplies to end users consisting of residential, agricultural, commercial, and industrial customers and to certain resellers in 21 states and the District of Columbia. See Note 15 for a discussion of the sale of a portion of our Retail Propane segment.
- Our Refined Products and Renewables segment conducts gasoline, diesel, ethanol, and biodiesel marketing operations, purchases refined petroleum and renewable products primarily in the Gulf Coast, Southeast and Midwest regions of the United States and schedules them for delivery at various locations throughout the country. In addition, in certain storage locations, our Refined Products and Renewables segment may also purchase unfinished gasoline blending components for subsequent blending into finished gasoline to supply our marketing business as well as third parties.

Recent Developments

On March 30, 2018, we sold a portion of our Retail Propane segment to DCC LPG (see Note 15). As a result, we deconsolidated this portion of our Retail Propane segment. As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Retail Propane segment have not been classified as discontinued operations.

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 ("GAAP"). The accompanying consolidated financial statements include our accounts and those of our controlled subsidiaries. Intercompany transactions and account balances have been eliminated in consolidation. Investments we do not control, but can exercise significant influence over, are accounted for using the equity method of accounting. We also own an undivided interest in a crude oil pipeline, and include our proportionate share of assets, liabilities, and expenses related to this pipeline in our consolidated financial statements.

Use of Estimates

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

Critical estimates we make in the preparation of our consolidated financial statements include, among others, determining the fair value of assets and liabilities acquired in business combinations, the fair value of derivative instruments,

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

the collectibility of accounts receivable, the recoverability of inventories, useful lives and recoverability of property, plant and equipment and amortizable intangible assets, the impairment of long-lived assets and goodwill, the fair value of asset retirement obligations, the value of equity-based compensation, and accruals for environmental matters. Although we believe these estimates are reasonable, actual results could differ from those estimates.

Fair Value Measurements

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

- Level 1: Quoted prices 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 (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability, and (iv) 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 forward commodity contracts. We determine the fair value of all of our derivative financial instruments utilizing pricing models for 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 inputs (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 a fair value measurement requires judgment, considering factors specific to the asset or liability.

Derivative Financial Instruments

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

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

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

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Revenue Recognition

We record product sales revenues when title to the product transfers to the purchaser, which typically occurs when the purchaser receives the product. We record terminaling, transportation, storage, and service revenues when the service is performed, and we record tank and other rental revenues over the lease term. Revenues for our Water Solutions segment are recognized when we obtain the wastewater at our treatment and disposal facilities.

The tariffs we charge for our pipeline transportation systems are primarily regulated by the Federal Energy Regulatory Commission. Our tariffs include provisions which allow us to deduct from our customer's inventory a small percentage of the products our customers transport on our pipeline systems. We refer to these product quantities as pipeline loss allowance. We receive pipeline loss allowances from our customers as consideration for product losses during the transportation of their products on our pipeline systems. Our customers are guaranteed delivery of the amount of their injected volumes, net of pipeline loss allowance, irrespective of what our actual product losses may be during the delivery process.

We report taxes collected from customers and remitted to taxing authorities, such as sales and use taxes, on a net basis. We include amounts billed to customers for shipping and handling costs within revenues in our consolidated statements of operations. We enter into certain contracts whereby we agree to purchase product from a counterparty and sell the same volume of product to the same counterparty at a different location or time. When such agreements are entered into at the same time and in contemplation of each other, we record the revenues for these transactions net of cost of sales.

Revenues during the years ended March 31, 2018, 2017 and 2016 include \$1.3 million, \$4.9 million and \$5.8 million, respectively, 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 all costs we incur to acquire products, including the costs of purchasing, terminaling, and transporting inventory, prior to delivery to our customers, in cost of sales. Cost of sales excludes depreciation of our property, plant and equipment.

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.

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 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 2014 to 2017 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.

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.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

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, 2018 or 2017.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (the "Act") was signed into law by the President of the United States. The Act amended the Internal Revenue Code of 1986 for taxable years beginning after December 31, 2017 and does not extend retroactively to any prior tax periods. As of March 31, 2018 and 2017, we do not have any deferred tax assets or liabilities. Any future deferred tax assets or liabilities will be valued based on the new corporate tax rate under the Act.

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.

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 collectibility 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 at the dates indicated:

	March 31, 2018			March 31, 2017		
Segment	Gross Receivable	Allowance for Doubtful Accounts	Net	Gross Receivable	Allowance for Doubtful Accounts	Net
	(in thousands)					
Crude Oil Logistics	$404,865	$—	$404,865	$345,049	$(3)	$345,046
Water Solutions	59,958	(2,952)	57,006	34,335	(2,789)	31,546
Liquids	131,006	(20)	130,986	94,390	(293)	94,097
Retail Propane	47,070	(1,146)	45,924	46,329	(1,280)	45,049
Refined Products and Renewables	435,136	(1,229)	433,907	285,664	(869)	284,795
Corporate and Other	—	—	—	74	—	74
Total	$1,078,035	$(5,347)	$1,072,688	$805,841	$(5,234)	$800,607

Changes in the allowance for doubtful accounts are as follows for the periods indicated:

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
Allowance for doubtful accounts, beginning of period	$(5,234)	$(6,928)	$(4,367)
Provision for doubtful accounts	(2,415)	(1,029)	(5,628)
Write off of uncollectible accounts	2,302	2,723	3,067
Allowance for doubtful accounts, end of period	$(5,347)	$(5,234)	$(6,928)

We did not have any customers that represented over 10% of consolidated revenues for fiscal years 2018, 2017 and 2016.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Inventories

Our inventories are valued at the lower of cost or net realizable value, with cost determined using either the weighted-average cost or the first in, first out (FIFO) methods, including the cost of transportation and storage, and with net realizable value defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. In performing this analysis, we consider fixed-price forward commitments and the opportunity to transfer propane inventory from our Liquids business to our Retail Propane business to sell the inventory in retail markets.

Inventories consist of the following at the dates indicated:

	March 31,	
	2018	2017
	(in thousands)	
Crude oil	$77,351	$146,857
Natural gas liquids:		
Propane	45,262	38,631
Butane	12,613	5,992
Other	6,515	6,035
Refined products:		
Gasoline	253,329	193,051
Diesel	115,983	98,237
Renewables:		
Ethanol	38,093	42,009
Biodiesel	10,596	21,410
Other	4,811	9,210
Total	$564,553	$561,432

Investments in Unconsolidated Entities

Investments we do not control, but can exercise significant influence over, are accounted for using the equity method of accounting. Investments in partnerships and limited liability companies, unless our investment is considered to be minor, and investments in unincorporated joint ventures are also accounted for using the equity method of accounting. Under the equity method, we do not report the individual assets and liabilities of these entities on our consolidated balance sheets; instead, our ownership interests are reported within investments in unconsolidated entities on 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 net assets of the investee. We consider distributions received from unconsolidated entities which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment and are classified as operating activities in our consolidated statements of cash flows. We consider distributions received from unconsolidated entities in excess of cumulative equity in earnings subsequent to the date of investment to be a return of investment and are classified as investing activities in our consolidated statements of cash flows.

Our investments in unconsolidated entities consist of the following at the dates indicated:

	Ownership	Date Acquired	March 31,

Entity	Segment	Interest (1)	or Formed	2018	2017
				(in thousands)	
Glass Mountain Pipeline, LLC (2)	Crude Oil Logistics	—%	December 2013	$—	$172,098
E Energy Adams, LLC (3)	Refined Products and Renewables	20%	December 2013	15,142	12,952
Water treatment and disposal facility (4)	Water Solutions	50%	August 2015	2,094	2,147
Victory Propane, LLC (5)	Retail Propane	50%	April 2015	—	226
Total				$17,236	$187,423

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

(1) Ownership interest percentages are at March 31, 2018.

(2) On December 22, 2017, we sold our previously held 50% interest in Glass Mountain Pipeline, LLC for net proceeds of $292.1 million and recorded a gain on disposal of $108.6 million during the three months ended December 31, 2017 within (gain) loss on disposal or impairment of assets, net in our consolidated statement of operations. As this sale transaction did not represent a strategic shift that will have a major effect on our operations or financial results, operations related to this portion of our Crude Oil Logistics segment have not been classified as discontinued operations.

(3) See Note 17 related to the sale of our interest in E Energy Adams, LLC subsequent to March 31, 2018.

(4) This is an investment in an unincorporated joint venture.

(5) As our investment is $0 at March 31, 2018, our proportionate share of Victory Propane, LLC's ("Victory Propane") losses have been recorded against the loan receivable we have with Victory Propane. See Note 13 for a further discussion of the loan receivable and a description of other transactions between us and Victory Propane.

Combined summarized financial information for all of our unconsolidated entities is as follows for the dates and periods indicated:

Balance sheets:

	March 31,	
	2018	2017
	(in thousands)	
Current assets	$25,232	$28,550
Noncurrent assets	$102,780	$294,705
Current liabilities	$17,300	$20,764
Noncurrent liabilities	$12,486	$17,119

Statements of operations:

	March 31,		
	2018	2017	2016
	(in thousands)		
Revenues	$187,368	$183,702	$273,857
Cost of sales	$117,101	$115,896	$107,425
Net income	$30,025	$17,969	$46,595

At March 31, 2018, cumulative equity earnings and cumulative distributions of our unconsolidated entities since they were acquired were $10.6 million and $11.2 million, respectively.

Variable Interest Entity

Victory Propane was formed as a joint venture in April 2015 by us and an unrelated third party. The business purpose of Victory Propane is to acquire and/or develop retail propane operations in a defined geographic area. In conjunction with the formation of Victory Propane, we agreed to provide Victory Propane a revolving line of credit of $5.0 million to be used for working capital and/or acquisition funding. Victory Propane began using this revolving line of credit shortly after operations commenced. At March 31, 2018, we provided a majority of Victory Propane's financing and have concluded that Victory Propane is a variable interest entity because the equity is not sufficient to fund Victory Propane's activities without additional subordinated financial support. Each joint venture member has an equal ownership interest in Victory Propane and has equal representation on Victory Propane's board of managers to make all significant decisions relating to the operations of Victory Propane. Therefore, we do not have the power to direct activities that significantly influence the economic performance of Victory Propane and have concluded that we are not the primary beneficiary. Our maximum exposure to loss related to Victory Propane is limited to the sum of our equity investment as shown in the table above and the outstanding loan receivable (see Note 13) at March 31, 2018.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Other Noncurrent Assets

Other noncurrent assets consist of the following at the dates indicated:

	March 31,	
	2018	2017
	(in thousands)	
Loan receivable (1)	$29,463	$40,684
Line fill (2)	34,897	30,628
Tank bottoms (3)	42,044	42,044
Minimum shipping fees - pipeline commitments (4)	88,757	67,996
Other	50,780	58,252
Total	$245,941	$239,604

(1) Represents the noncurrent portion of 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 product we are required to leave on certain third-party owned pipelines under long-term shipment commitments. At March 31, 2018, line fill consisted of 360,425 barrels of crude oil and 262,000 barrels of propane. At March 31, 2017, line fill consisted of 427,193 barrels of crude oil. Line fill held in pipelines we own is included within property, plant and equipment (see Note 5).

(3) Tank bottoms, which are product volumes required for the operation of storage tanks, are recorded at historical cost. We recover tank bottoms when the storage tanks are removed from service. At March 31, 2018 and 2017, tank bottoms held in third party terminals consisted of 366,212 barrels and 366,212 barrels of refined products, respectively. Tank bottoms held in terminals we own are included within property, plant and equipment (see Note 5).

(4) Represents the minimum shipping fees paid in excess of volumes shipped for two contracts. This amount can be recovered when volumes shipped exceed the minimum monthly volume commitment (see Note 9). Under these contracts, we currently have 2.1 years and 2.5 years, respectively, in which to ship the excess volumes.

Accrued Expenses and Other Payables

Accrued expenses and other payables consist of the following at the dates indicated:

	March 31,	
	2018	2017
	(in thousands)	
Accrued compensation and benefits	$22,841	$22,227
Excise and other tax liabilities	41,731	64,051
Derivative liabilities	51,039	27,622
Accrued interest	40,024	44,418
Product exchange liabilities	11,842	1,693
Deferred gain on sale of general partner interest in TLP	30,113	30,113
Other	32,497	17,001
Total	$230,087	$207,125

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Sale of General Partner Interest in TransMontaigne Partners L.P. (“TLP”)

As previously reported, on February 1, 2016, we sold our general partner interest in TLP to an affiliate of ArcLight Capital Partners (“ArcLight”) for net proceeds of $343.1 million and recorded a gain on disposal of $329.9 million during the three months ended March 31, 2016. As part of this transaction, we retained TransMontaigne Product Services LLC, including its marketing business, customer contracts and its line space on the Colonial and Plantation pipelines, which is a significant part of our Refined Products and Renewables segment. We also entered into lease agreements whereby we will remain the long-term exclusive tenant in the TLP Southeast terminal system. As a result of entering into these leases, we deferred $204.6 million of the gain on the sale and will recognize this amount over our future lease payment obligations, which is approximately seven years (see below accounting guidance that will impact the recognition of the deferred gain). During the years ended March 31, 2018, 2017 and 2016, we recognized $30.1 million, $30.1 million and $5.0 million, respectively, of the deferred gain in our consolidated statements of operations. These gains are reported within (gain) loss on disposal or impairment of assets, net in our consolidated statement of operations. Expected amortization of the remaining deferred gain is as follows (in thousands):

Year Ending March 31,	
2019	$30,113
2020	30,113
2021	29,593
2022	26,993
2023	22,494
Total	$139,306

Within our March 31, 2018 consolidated balance sheet, the current portion of the deferred gain, $30.1 million, is recorded in accrued expenses and other payables and the long-term portion, $109.2 million, is recorded in other noncurrent liabilities. See “Recent Accounting Pronouncements” below for a discussion of the accounting for the gain upon the adoption of ASU No. 2014-09.

Sale of TLP Common Units

On April 1, 2016, we sold all of the TLP common units we owned to ArcLight for approximately $112.4 million in cash and recorded a gain on disposal of $104.1 million during the year ended March 31, 2017. This gain is reported within (gain) loss on disposal or impairment of assets, net in our consolidated statement of operations.

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 (gain) loss on disposal or impairment of assets, net. We compute depreciation expense of our property, plant and equipment using the straight-line method over the estimated useful lives of the assets (see Note 5).

Intangible Assets

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

Impairment of Long-Lived Assets

We evaluate the carrying value of our long-lived assets (property, plant and equipment and amortizable intangible assets) for potential impairment when events and circumstances warrant such a review. A long-lived asset group is considered impaired when the anticipated undiscounted future cash flows from the use and eventual disposition of the asset group is less than its carrying value. 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. See Note 5 and Note 7 for a further discussion of long-lived asset impairments recognized in the consolidated financial statements.

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

Goodwill

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. Business combinations are accounted for using the "acquisition method" (see Note 4). We expect that all of our goodwill at March 31, 2018 is deductible for federal income tax purposes.

Goodwill and indefinite-lived intangible assets are not amortized, but instead are evaluated for impairment at least annually. We perform our annual assessment of impairment during the fourth quarter of our fiscal year, and more frequently if circumstances warrant.

To perform this assessment, we first 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 does not exceed its carrying amount, we calculate the fair value for the reporting unit and compare the amount to 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, goodwill is considered to be impaired and the goodwill balance is reduced by the difference between the fair value and carrying amount of the reporting unit.

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 goodwill impairment assessment included market participant considerations and future forecasted operating results. Changes in operating results and other assumptions could materially affect these estimates. See Note 6 for a further discussion and analysis of our goodwill impairment assessment.

Product Exchanges

Quantities of products receivable or returnable under exchange agreements are reported within prepaid expenses and other current assets and 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.

Advance Payments Received from Customers

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

Noncontrolling Interests

Noncontrolling interests represent the portion of certain consolidated subsidiaries that are owned by third parties. Amounts are adjusted by the noncontrolling interest holder's proportionate share of the subsidiaries' earnings or losses each period and any distributions that are paid. Noncontrolling interests are reported as a component of equity, unless the noncontrolling interest is considered redeemable, in which case the noncontrolling interest is recorded between liabilities and equity (mezzanine or temporary equity) in our consolidated balance sheet. The redeemable noncontrolling interest is adjusted at each balance sheet date to its maximum redemption value if the amount is greater than the carrying value. The following table summarizes changes in our redeemable noncontrolling interest in our consolidated balance sheets (in thousands):

Balance at March 31, 2016	$—
Transfer of redeemable noncontrolling interest	3,072
Balance at March 31, 2017	3,072
Net income attributable to redeemable noncontrolling interest	1,030
Redeemable noncontrolling interest valuation adjustment	5,825
Balance at March 31, 2018	$9,927

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

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 fair value of the assets acquired and liabilities assumed in a business combination. As discussed in Note 4, certain of our acquisitions 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 discussed in Note 4, we made certain adjustments during the year ended March 31, 2018 to our estimates of the acquisition date fair values of the assets acquired and liabilities assumed in business combinations that occurred during the year ended March 31, 2017.

Reclassifications

We have reclassified certain prior period financial statement information to be consistent with the classification methods used in the current fiscal year. These reclassifications did not impact previously reported amounts of assets, liabilities, equity, net income, or cash flows.

Recent Accounting Pronouncements

In August 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-15, "Statement of Cash Flows-Classification of Certain Cash Receipts and Cash Payments." The ASU requires cash payments not made soon after the acquisition date of a business combination by an acquirer to settle a contingent consideration liability to be separated and classified as cash outflows for financing activities and operating activities. Cash payments up to the amount of the contingent consideration liability recognized at the acquisition date (including measurement-period adjustments) should be classified as financing activities and any excess should be classified as operating activities. We adopted this ASU effective April 1, 2017 and have revised previously reported information.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments-Credit Losses." The ASU requires a financial asset (or a group of financial assets) measured at amortized cost to be presented at the net amount expected to be collected, which would include accounts receivable. The measurement of expected credit losses is based on relevant information about past events, including historical experience, current conditions, and reasonable and supportable forecasts that affect the collectibility of the reported amount. The ASU is effective for the Partnership beginning April 1, 2020, and requires a modified retrospective method of adoption, although early adoption is permitted. We are currently in the process of assessing the impact of this ASU on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, "Leases." The ASU will replace previous lease accounting guidance in GAAP. The ASU requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. The ASU retains a distinction between finance leases and operating leases. The ASU is effective for the Partnership beginning April 1, 2019, and requires a modified retrospective method of adoption. We are currently in the process of compiling a database of leases and analyzing each lease to assess the impact under this ASU on our consolidated financial statements.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers." The ASU will replace the revenue recognition requirements in Topic 605, "Revenue Recognition", and most industry-specific guidance. 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. ASU No. 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than required under existing U.S. GAAP. In addition, the standard requires more extensive disaggregated revenue disclosures in interim and annual financial statements.

The guidance permits the use of either a full retrospective or a modified retrospective transaction approach. We adopted this standard on April 1, 2018 using the modified retrospective approach. Other than discussed below, the cumulative effect of adopting the new standard was immaterial and related primarily to non-cash consideration received in our Water Solutions segment. Based on our evaluation, we anticipate that from time to time, differences in the timing of revenues earned and our right to invoice customers may create contract assets or liabilities. These differences in timing would be the result of contracts that contain minimum volume commitments and tiered pricing provisions, primarily within our Water Solutions segment. In addition, we are in the process of implementing appropriate changes to our business processes, systems and controls to support recognition and disclosure under this standard.

As discussed above under "Sale of General Partner Interest in TLP," we deferred a portion of the gain as this transaction was accounted for under the real estate guidance in ASC 360-20, Property, Plant and Equipment and have been amortizing the gain over the life of the lease agreements. ASU No. 2014-09 supersedes the guidance in ASC 360-20 on determining the gain or loss recognized upon the derecognition of nonfinancial assets, including in-substance nonfinancial assets, that are not an output of an entity's ordinary activities. This guidance is codified in ASC 610-20. ASC 610-20 does not amend or supersede the guidance on how to determine the gain or loss on the derecognition of a subsidiary or group of assets that meets the definition of a business, which is codified in ASC 810-10-40. ASU No. 2017-05 eliminated the scope exception of "in substance real estate" from ASC 810-10-40. Therefore, upon the adoption of ASU No. 2014-09 and ASU No. 2017-05, it was determined that the transaction should be accounted for under the guidance of ASC 810-10-40 and utilizing the modified retrospective approach of adoption, the deferred gain as of March 31, 2018 of $139.3 million will be recognized in the beginning balance of retained earnings as part of our cumulative effect adjustment.

Note 3—(Loss) Income Per Common Unit

The following table presents our calculation of basic and diluted weighted average units outstanding for the periods indicated:

	Year Ended March 31,		
	2018	2017	2016
Weighted average units outstanding during the period:			
Common units - Basic	120,991,340	108,091,486	104,838,886
Effect of Dilutive Securities:			
Performance awards	—	173,087	—
Warrants	—	3,586,048	—
Common units - Diluted	120,991,340	111,850,621	104,838,886

For the year ended March 31, 2018, the Service Awards (as defined herein), Performance Awards (as defined herein), warrants and Class A Preferred Units (as defined herein) were considered antidilutive. For the year ended March 31, 2017, the Class A Preferred Units were considered antidilutive and for the years ended March 31, 2017, and 2016, the Service Awards were considered antidilutive. In addition, the Performance Awards were antidilutive for the year ended March 31, 2016.

Our (loss) income per common unit is as follows for the periods indicated:

	Year Ended March 31,		
	2018	2017	2016
	(in thousands, except unit and per unit amounts)		
Net (loss) income	$ (69,605)	$ 143,874	$ (187,097)
Less: Net income attributable to noncontrolling interests	(240)	(6,832)	(11,832)
Less: Net income attributable to redeemable noncontrolling interests	(1,030)	—	—
Net (loss) income attributable to NGL Energy Partners LP	(70,875)	137,042	(198,929)
Less: Distributions to preferred unitholders	(59,697)	(30,142)	—
Less: Net income allocated to general partner (1)	(5)	(232)	(47,620)
Less: Repurchase of warrants (2)	(349)	—	—
Net (loss) income allocated to common unitholders	$ (130,926)	$ 106,668	$ (246,549)

Basic (loss) income per common unit	$ (1.08)	$ 0.99	$ (2.35)
Diluted (loss) income per common unit	$ (1.08)	$ 0.95	$ (2.35)
Basic weighted average common units outstanding	120,991,340	108,091,486	104,838,886
Diluted weighted average common units outstanding	120,991,340	111,850,621	104,838,886

(1) Net income allocated to the general partner includes distributions to which it is entitled as the holder of incentive distribution rights.

(2) This amount represents the excess of the repurchase price over the fair value of the warrants, as discussed further in Note 10.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Note 4—Acquisitions

The following summarizes our acquisitions during the year ended March 31, 2018:

Acquisition of Remaining Interest in NGL Solids Solutions, LLC

On April 17, 2017, we entered into a purchase and sale agreement with the party owning the 50% noncontrolling interest in NGL Solids Solutions, LLC, a consolidated subsidiary in our Water Solutions segment. Total consideration was $23.1 million, which consisted of cash of $20.0 million and the termination of a non-compete agreement that we valued at $3.1 million, and in return we received the following:

- The remaining 50% interest in NGL Solids Solutions, LLC; and
- Two parcels of land to develop saltwater disposal wells.

We accounted for the transaction as an acquisition of assets. Acquiring assets in groups requires not only ascertaining the cost of the asset (or net asset) group but also allocating that cost to the individual assets (or individual assets and liabilities) that make up the group. The cost of a group of assets acquired in an asset acquisition is allocated to the individual assets acquired or liabilities assumed/released based on their relative fair values and does not give rise to goodwill or bargain purchase gains. We allocated $22.9 million to noncontrolling interest and $0.2 million to land. The acquisition of the remaining interest was accounted for as an equity transaction, no gain or loss was recorded and the carrying value of the noncontrolling interest was adjusted to reflect the change in ownership interest of the subsidiary. As of the date of the transaction, the 50% noncontrolling interest had a carrying value of $16.6 million. For the termination of the non-compete agreement, we recorded a gain of $1.3 million, which included the carrying value of the non-compete agreement intangible asset that was written off (see Note 7). This gain was recorded within (gain) loss on disposal or impairment of assets, net in our consolidated statement of operations during the year ended March 31, 2018.

Retail Propane Businesses

During the year ended March 31, 2018, we acquired seven retail propane businesses for total consideration of $30.9 million, of which three of those businesses were part of the sale of a portion of our Retail Propane segment (see Note 15). The agreements for these acquisitions contemplate post-closing payments for certain working capital items. We incurred and charged to general and administrative expense $0.1 million of costs related to these acquisitions during the year ended March 31, 2018.

We are in the process of identifying and determining the fair values of the assets acquired and liabilities assumed for these retail propane businesses, and as a result, the estimates of fair value at March 31, 2018 are subject to change. The following table summarizes the preliminary estimates of the fair values of the assets acquired and liabilities assumed (in thousands):

Current assets	$2,372
Property, plant and equipment	11,370
Goodwill	2,251
Intangible assets	16,765
Current liabilities	(1,588)
Other noncurrent liabilities	(291)
Fair value of net assets acquired	$30,879

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 represents a premium paid to acquire the skilled workforce of each of the businesses acquired and the ability to expand into new markets. We expect that all of the goodwill will be deductible for federal income tax purposes.

The operations of these retail propane businesses have been included in our consolidated statement of operations since their acquisition date. Our consolidated statement of operations for the year ended March 31, 2018 includes revenues of $17.0 million and operating income of $1.7 million that were generated by the operations of three of these retail propane businesses. The revenues and operating income of the other retail propane business acquisitions are not considered material.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

The following summarizes the status of the preliminary purchase price allocation of acquisitions prior to April 1, 2017:

Water Solutions Facilities

During the year ended March 31, 2018, we completed the acquisition accounting for two water solutions facilities. Due to the receipt of additional information, we recorded a decrease of $0.2 million to property, plant and equipment and an increase of less than $0.1 million to other noncurrent liabilities related to an asset retirement obligation. The offset of these adjustments was recorded to goodwill.

Retail Propane Businesses

During the year ended March 31, 2018, we completed the acquisition accounting for four retail propane businesses. Due to the receipt of additional information, we recorded a decrease of $0.2 million to current assets and a decrease of less than $0.1 million to property, plant and equipment. The offset of these adjustments was recorded to goodwill. In addition, we paid $0.4 million in cash to the sellers during the year ended March 31, 2018 for consideration that was held back at the acquisition date, which we recorded as a liability within accrued expenses and other payables in our consolidated balance sheet.

Natural Gas Liquids Facilities

During the year ended March 31, 2018, we completed the acquisition accounting for certain natural gas liquids facilities acquired in January 2017. There were no material adjustments to the fair value of assets acquired and liabilities assumed during the year ended March 31, 2018.

Note 5—Property, Plant and Equipment

Our property, plant and equipment consists of the following at the dates indicated:

Description	Estimated Useful Lives	March 31, 2018	2017
		(in thousands)	
Natural gas liquids terminal and storage assets	2-30 years	$238,487	$207,825
Pipeline and related facilities	30-40 years	243,616	248,582
Refined products terminal assets and equipment	15-25 years	6,736	6,736
Retail propane equipment	2-30 years	197,113	239,417
Vehicles and railcars	3-25 years	184,273	198,480
Water treatment facilities and equipment	3-30 years	601,139	557,100
Crude oil tanks and related equipment	2-30 years	218,588	203,003
Barges and towboats	5-30 years	92,712	91,037
Information technology equipment	3-7 years	38,564	43,880
Buildings and leasehold improvements	3-40 years	167,472	161,957
Land		63,600	56,545
Tank bottoms and line fill (1)		20,118	24,462
Other	3-20 years	13,145	39,132
Construction in progress		77,450	87,711
		2,163,013	2,165,867

Accumulated depreciation	(443,066)	(375,594)
Net property, plant and equipment	$1,719,947	$1,790,273

(1) Tank bottoms, which are product volumes required for the operation of storage tanks, are recorded at historical cost. We recover tank bottoms when the storage tanks are removed from service. Line fill, which represents our portion of the product volume required for the operation of the proportionate share of a pipeline we own, is recorded at historical cost.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

The following table summarizes depreciation expense and capitalized interest expense for the periods indicated:

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
Depreciation expense	$128,808	$119,707	$136,938
Capitalized interest expense	$182	$6,887	$4,012

We record losses (gains) from the sales of property, plant and equipment and any write-downs in value due to impairment within (gain) loss on disposal or impairment of assets, net in our consolidated statement of operations. The following table summarizes losses (gains) on the disposal or impairment of property, plant and equipment by segment for the periods indicated:

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
Crude Oil Logistics (1)	$(3,144)	$8,124	$54,952
Water Solutions	8,117	7,169	1,485
Liquids	639	92	(2,992)
Retail Propane	1,136	(287)	(137)
Refined Products and Renewables	15	91	3,080
Corporate	8	(1)	—
Total	$6,771	$15,188	$56,388

(1) Amounts for the year ended March 31, 2018 primarily relate to losses from the disposal of certain assets and the write-down of other assets, offset by a gain related to the sale of excess pipe. Amounts for the year ended March 31, 2017 primarily relate to losses from the sale of certain assets, including excess pipe. Amounts for the year ended March 31, 2016 primarily relate to the write-down of pipe we no longer expected to use in our originally planned pipeline from Colorado to Oklahoma.

Note 6—Goodwill

The following table summarizes changes in goodwill by segment for the periods indicated (in thousands):

	Crude Oil Logistics	Water Solutions	Liquids	Retail Propane	Refined Products and Renewables	Total
	(in thousands)					
Balances at March 31, 2016	$579,846	$290,915	$266,046	$127,428	$ 51,127	$1,315,362
Revisions to acquisition accounting	—	(1,110)	—	(56)	—	(1,166)
Acquisitions	—	9,803	—	3,055	—	12,858
Adjustment to initial impairment estimate	—	124,662	—	—	—	124,662
Balances at March 31, 2017	579,846	424,270	266,046	130,427	51,127	1,451,716
Revisions to acquisition accounting (Note 4)	—	195	—	232	—	427
Acquisitions (Note 4)	—	—	—	2,251	—	2,251
Impairment	—	—	(116,877)	—	—	(116,877)
Disposals (Note 15)	—	—	—	(24,959)	—	(24,959)
Balances at March 31, 2018	$579,846	$424,465	$149,169	$107,951	$ 51,127	$1,312,558

Fiscal Year 2018 Goodwill Impairment Assessment

Due to the decreased demand for natural gas liquid storage and resulting decline in revenues and earnings as compared to actual and projected results of prior and future periods, we tested the goodwill within our natural gas liquids salt cavern storage reporting unit (“Sawtooth reporting unit”), which is part of our Liquids segment, for impairment at September 30, 2017. We estimated the fair value of our Sawtooth reporting unit based on the income approach, also known as the discounted cash flow method, which utilizes the present value of future expected cash flows to estimate the fair value. The future cash flows of our Sawtooth 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: (i) expected storage volumes, which are assumed to increase in the coming years due to increased production of natural gas liquids, (ii) expected propane and butane prices and (iii) expected rental fees. We assumed a 2% per year increase in commodity prices and a 4% increase in rental fees per year starting in April 2018, and held such prices and fees flat for periods in our model beyond our 2023 fiscal year. For expenses, we assumed an increase consistent with the increase in storage volumes, and maintenance capital was held flat throughout the model. The discount rate used in our discounted cash flow method was a risk adjusted weighted average cost of capital calculated as of September 30, 2017 of 12%. The discounted cash flow results indicated that the estimated fair value of our Sawtooth reporting unit was less than its carrying value by approximately 32% at September 30, 2017.

During the three months ended September 30, 2017, we recorded a goodwill impairment charge of $116.9 million, which was recorded within (gain) loss on disposal or impairment of assets, net, in our consolidated statement of operations. At September 30, 2017, our Sawtooth reporting unit had a goodwill balance of $66.2 million.

In Note 15, we discuss a transaction in which we formed a joint venture which included our Sawtooth salt dome storage facility. As a result of this transaction, we tested the goodwill of our Sawtooth reporting unit, immediately prior to the closing of this transaction, for impairment. As of March 30, 2018, our Sawtooth reporting unit had a goodwill balance of $66.2 million. Similar to the analysis we performed as of September 30, 2017, as discussed above, we estimated the fair value of our Sawtooth reporting unit based on the income approach, also known as the discounted cash flow method, which utilizes the present value of future expected cash flows to estimate the fair value. The future cash flows of our Sawtooth 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: (i) expected storage volumes, which are assumed to increase in the coming years due to increased production of natural gas liquids, (ii) expected propane and butane prices and (iii) expected rental fees. We assumed a 2% per year increase in commodity prices and a 4% increase in rental fees per year starting in April 2018, and held such prices and fees flat for periods in our model beyond our 2023 fiscal year. For expenses, we assumed an increase consistent with the increase in storage volumes, and maintenance capital was held flat throughout the model. The discount rate used in our discounted cash flow method was a risk adjusted weighted average cost of capital calculated as of March 30, 2018 of 12.4%. The discounted cash flow results indicated that the estimated fair value of our Sawtooth reporting unit was greater than its carrying value by approximately 2% at March 30, 2018.

Our estimated fair value is predicated upon management’s assumption of the growth in the production of natural gas liquids and the decline in the use of railcars to store natural gas liquids. We used these assumptions to estimate the demand for storage at our facility and the revenue generated by customers reserving capacity at our facility. Due to the current volatility in commodity prices and the excess railcars currently in the market, we believe it is reasonably possible that the need for underground storage we estimate in our model does not materialize, such that our estimate of fair value could change and result in further impairment of the goodwill in our Sawtooth reporting unit.

We performed a qualitative assessment as of January 1, 2018 to determine whether it was more likely than not that the fair value of each reporting unit was greater than the carrying value of the reporting unit. Based on these qualitative assessments, we determined that the fair value of each of these reporting units was more likely than not greater than the carrying value of the reporting units.

Fiscal Year 2017 Goodwill Impairment Assessment

We performed a qualitative assessment as of January 1, 2017 to determine whether it was more likely than not that the fair value of each reporting unit was greater than the carrying value of the reporting unit. Based on these qualitative assessments, we determined that the fair value of each of these reporting units was more likely than not greater than the carrying value of the reporting units.

Fiscal Year 2016 Goodwill Impairment Assessment

Due to the continued decline in crude oil prices and crude oil production, we tested the goodwill within our Water Solutions reporting unit for impairment at December 31, 2015. At December 31, 2015, our Water Solutions reporting unit had a goodwill balance of $660.8 million. We 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: (i) 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 (ii) the crude oil price environment as reflected in crude oil forward prices as of the test date. In performing the discounted cash flow analysis, we utilized reports issued by independent third parties projecting crude oil prices through 2018. We assumed an approximate $1/barrel increase each quarter for the periods beyond those represented in the reports, with crude oil reaching $65/barrel by the fourth quarter of 2021. We used a price of $32/barrel for the fourth quarter of 2016, the starting point of our cash flow projections. We kept prices constant at $65/barrel for periods in our model beyond 2021. Consistent with observed disposal volume trends, the disposal volumes were based on an expectation of a certain amount of production returning at certain crude oil price levels. For expenses, we assumed an increase consistent with the increase in disposal volumes. The discount rate used in our discounted cash flow method was calculated by using the average of the range of discount rates from a recent water solutions transaction similar in size to our Water Solutions reporting unit. The discounted cash flow results indicated that the estimated fair value of our Water Solutions reporting unit was greater than its carrying value by approximately 9% at December 31, 2015.

As a result of the continued decline in crude oil production, its continued adverse impact on our Water Solutions reporting unit and the completion of our annual budget process we decided to test the goodwill within our Water Solutions reporting unit for impairment as of March 31, 2016 as it was more likely than not that the fair value of our Water Solutions reporting unit was less than the carrying amount. Similar to the testing performed as of December 31, 2015, fair value of the Water Solutions reporting unit was based on the income approach, which utilizes the present value of cash flows to estimate the fair value. We utilized the same pricing, expense and discount rate assumptions in our current model as described above but adjusted our expected water volumes and percentage recovered hydrocarbons to match what we have budgeted for our fiscal year 2017. Volumes budgeted for fiscal year 2017 were heavily influenced by the reporting unit’s operating results from the fourth quarter of fiscal year 2016. We utilized the same assumptions related to anticipated volume growth as above. The discounted cash flow results indicated that the estimated fair value of our Water Solutions reporting unit was less than its carrying value by approximately 11% at March 31, 2016.

During the year ended March 31, 2016, we recorded an estimated goodwill impairment charge of $380.2 million, which was recorded within (gain) loss on disposal or impairment of assets, net in our consolidated statements of operations. This was an initial estimate pending the completion of valuation work being performed for us by a third party valuation firm. At March 31, 2016, our Water Solutions reporting unit had a goodwill balance of $290.9 million.

During the three months ended June 30, 2016, we finalized our goodwill impairment analysis, with the assistance of a third party valuation firm. As a result of finalizing our analysis, we determined that we needed to reverse $124.7 million of the previously recorded goodwill impairment estimate recorded during the year ended March 31, 2016. The adjustment was due primarily to the change in the fair value of our customer relationship intangible assets. With the assistance of the third party valuation firm, inputs such as revenue growth rates and attrition rates related to existing customers were refined to better correlate with our historical revenue growth and attrition rates of our existing customers in our Water Solutions reporting unit. This change resulted in a lower fair value allocated to customer relationships and higher value to goodwill than in our preliminary calculation. We recorded the adjustment within (gain) loss on disposal or impairment of assets, net in our consolidated statement of operations. At June 30, 2016, our Water Solutions reporting unit had a goodwill balance of $423.7 million.

For our other reporting units, we performed a qualitative assessment as of January 1, 2016 to determine whether it was more likely than not that the fair value of each reporting unit was greater than the carrying value of the reporting unit.

Based on these qualitative assessments, we determined that the fair value of each of these reporting units was more likely than not greater than the carrying value of the reporting units.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Note 7—Intangible Assets

Our intangible assets consist of the following at the dates indicated:

Description	Amortizable Lives	March 31, 2018 Gross Carrying Amount	Accumulated Amortization	Net	March 31, 2017 Gross Carrying Amount	Accumulated Amortization	Net
		(in thousands)					
Amortizable:							
Customer relationships	3-20 years	$882,382	$(372,944)	$509,438	$906,782	$(316,242)	$590,540
Customer commitments	10 years	310,000	(43,917)	266,083	310,000	(12,917)	297,083
Pipeline capacity rights	30 years	161,785	(17,045)	144,740	161,785	(11,652)	150,133
Rights-of-way and easements	1-40 years	63,995	(3,214)	60,781	63,402	(2,154)	61,248
Executory contracts and other agreements	3-30 years	42,919	(15,424)	27,495	29,036	(20,457)	8,579
Non-compete agreements	2-32 years	17,779	(7,410)	10,369	32,984	(17,762)	15,222
Trade names	1-10 years	3,601	(1,909)	1,692	15,439	(13,396)	2,043
Debt issuance costs (1)	5 years	40,992	(24,593)	16,399	38,983	(20,025)	18,958
Total amortizable		1,523,453	(486,456)	1,036,997	1,558,411	(414,605)	1,143,806
Non-amortizable:							
Trade names		17,485	—	17,485	20,150	—	20,150
Total non-amortizable		17,485	—	17,485	20,150	—	20,150
Total		$1,540,938	$(486,456)	$1,054,482	$1,578,561	$(414,605)	$1,163,956

(1) Includes debt issuance costs related to the Revolving Credit Facility (as defined herein). Debt issuance costs related to fixed-rate notes are reported as a reduction of the carrying amount of long-term debt. We incurred $9.7 million in debt issuance costs related to the February 2017 amendment and restatement of our Credit Agreement (as defined herein).

The weighted-average remaining amortization period for intangible assets is approximately 13.4 years.

Write off of Intangible Assets

During the year ended March 31, 2018, we wrote off $1.8 million related to the non-compete agreement which was terminated as part of our acquisition of the remaining interest in NGL Solids Solutions, LLC (see Note 4). In connection with the amendment and restatement of our Credit Agreement (as defined herein) in February 2017, we wrote off $4.5 million of deferred debt issuance costs. During the year ended March 31, 2017, we wrote-off $5.2 million related to the value of an indefinite-lived trade name intangible asset in conjunction with finalizing our goodwill impairment analysis (see Note 6). In addition, as a result of terminating the development agreement in the Water Solutions segment in June 2016 (see Note 15), we incurred a loss of $5.8 million to write off the water facility development agreement. The losses for the years ended March 31, 2018 and 2017 are reported within (gain) loss on disposal or impairment of assets, net in our consolidated statement of operations.

Amortization expense is as follows for the periods indicated:

Recorded In	Year Ended March 31, 2018	2017	2016

	(in thousands)		
Depreciation and amortization	$123,904	$103,498	$91,986
Cost of sales	6,099	6,828	6,700
Interest expense	4,568	4,471	8,942
Total	$134,571	$114,797	$107,628

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Expected amortization of our intangible assets is as follows (in thousands):

Year Ending March 31,	
2019	$129,131
2020	125,745
2021	112,630
2022	97,517
2023	86,513
Thereafter	485,461
Total	$1,036,997

Note 8—Long-Term Debt

Our long-term debt consists of the following at the dates indicated:

	March 31, 2018			March 31, 2017		
	Face Amount	Unamortized Debt Issuance Costs (1)	Book Value	Face Amount	Unamortized Debt Issuance Costs (1)	Book Value
	(in thousands)					
Revolving credit facility:						
Expansion capital borrowings	$—	$ —	$—	$—	$ —	$—
Working capital borrowings	969,500	—	969,500	814,500	—	814,500
Senior secured notes	—	—	—	250,000	(4,559)	245,441
Senior unsecured notes:						
5.125% Notes due 2019	353,424	(1,653)	351,771	379,458	(3,191)	376,267
6.875% Notes due 2021	367,048	(4,499)	362,549	367,048	(5,812)	361,236
7.500% Notes due 2023	615,947	(8,542)	607,405	700,000	(11,329)	688,671
6.125% Notes due 2025	389,135	(5,951)	383,184	500,000	(8,567)	491,433
Other long-term debt	11,415	—	11,415	15,525	—	15,525
	2,706,469	(20,645)	2,685,824	3,026,531	(33,458)	2,993,073
Less: Current maturities	3,196	—	3,196	29,590	—	29,590
Long-term debt	$2,703,273	$ (20,645)	$2,682,628	$2,996,941	$ (33,458)	$2,963,483

(1) Debt issuance costs related to the Revolving Credit Facility are reported within intangible assets, rather than as a reduction of the carrying amount of long-term debt.

Amortization expense for debt issuance costs related to long-term debt in the table above was $6.1 million, $3.3 million and $4.6 million during the years ended March 31, 2018, 2017 and 2016.

Expected amortization of debt issuance costs is as follows (in thousands):

Year Ending March 31,	
2019	$4,945
2020	4,031
2021	3,658
2022	3,076
2023	2,388
Thereafter	2,547

Total	$20,645

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Credit Agreement

We are party to a $1.765 billion credit agreement (the "Credit Agreement") with a syndicate of banks, which was amended and restated in February 2017. As of March 31, 2018, 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"). Our Revolving Credit Facility includes an "accordion" feature that allows us to increase the capacity by $300 million if new lenders wish to join the syndicate or if current lenders wish to increase their commitments. Our Revolving Credit Facility also allows us to reallocate amounts between the Expansion Capital Facility and Working Capital Facility. At March 31, 2018, we had $100.0 million reallocated from the Working Capital Facility to the Expansion Capital Facility.

At March 31, 2018, the Expansion Capital Facility had a total capacity of $565.0 million for cash borrowings and the Working Capital Facility had a total capacity of $1.2 billion for cash borrowings and letters of credit. At that date, we had outstanding letters of credit of $175.7 million on the Working Capital Facility. Amounts outstanding for letters of credit are not recorded as long-term debt on our consolidated balance sheets, although they decrease our borrowing capacity under the Working Capital Facility. The capacity available under the Working Capital Facility may be limited by a "borrowing base" (as defined in the Credit Agreement), which is calculated based on the value of certain working capital items at any point in time.

The commitments under the Credit Agreement expire on October 5, 2021. We have the right to prepay outstanding borrowings under the Credit Agreement without incurring any penalties, and prepayments of principal may be required if we enter into certain transactions to sell assets or obtain new borrowings. The Credit Agreement is secured by substantially all of our assets.

All borrowings under the Credit Agreement bear interest, at our option, at either (i) an alternate base rate plus a margin of 0.50% to 2.00% per year or (ii) an adjusted LIBOR rate plus a margin of 1.50% to 3.00% per year. The applicable margin is determined based on our leverage ratio (as defined in the Credit Agreement). At March 31, 2018, the borrowings under the Credit Agreement had a weighted average interest rate of 4.99%, calculated as the weighted average LIBOR rate of 1.84% plus a margin of 3.00% for LIBOR borrowings and the prime rate of 4.75% plus a margin of 2.00% on alternate base rate borrowings. At March 31, 2018, the interest rate in effect on letters of credit was 3.00%. Commitment fees are charged at a rate ranging from 0.375% to 0.50% on any unused capacity.

On June 2, 2017, we amended our Credit Agreement. The amendment modified our financial covenants. In addition, it also restricts us from increasing our distribution rate over the amount paid in the preceding quarter if our leverage ratio is greater than 4.25 to 1.

On February 5, 2018, we amended our Credit Agreement. The amendment, among other things, amended the defined term "Consolidated EBITDA" to include the "Accrued Blenders Tax Credits" (as defined in the Credit Agreement) solely for the two quarters ended December 31, 2017 and March 31, 2018.

On March 6, 2018, we amended our Credit Agreement. In the amendment, the lenders consented to, subject to the consummation of the initial Sawtooth disposition, release each Sawtooth entity from its guaranty and other obligations under the loan documents. In return, the Partnership agreed to use the net proceeds of each Sawtooth disposition to pay down existing indebtedness no later than five business days after the consummation of such Sawtooth disposition.

On May 24, 2018, we amended our Credit Agreement to, among other things, modify our interest coverage ratio financial covenant for periods beginning March 31, 2018 and thereafter and to add a total leverage indebtedness ratio covenant, to be measured beginning March 31, 2019. Additionally, the amendment specifies that, should our leverage ratio be greater than 4.00 to 1 with respect to the quarter ended September 30, 2018, commitments under our Expansion Capital Facility will be decreased, immediately and permanently by $100.0 million.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

The following table summarizes the debt covenant levels specified in the Credit Agreement as of March 31, 2018 (as modified on May 24, 2018):

Period Beginning	Leverage Ratio (1)	Senior Secured Leverage Ratio (1)	Interest Coverage Ratio (2)	Total Leverage Indebtedness Ratio (1)
March 31, 2018	4.75	3.25	2.50	—
December 31, 2018	4.75	3.25	2.75	—
March 31, 2019 and thereafter	4.50	3.25	2.75	6.50

(1) Represents the maximum ratio for the period presented.
(2) Represents the minimum ratio for the period presented.

At March 31, 2018, our leverage ratio was approximately 4.41 to 1, our senior secured leverage ratio was approximately 0.02 to 1 and our interest coverage ratio was approximately 2.51 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, 2018, we were in compliance with the covenants under the Credit Agreement.

Senior Secured Notes

On June 19, 2012, we entered into the Note Purchase Agreement (as amended, the "Senior Secured Notes Purchase Agreement") whereby we issued $250.0 million of senior secured notes in a private placement (the "Senior Secured Notes"). The Senior Secured Notes bear interest at a fixed rate of 6.65% which is payable quarterly. The Senior Secured 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. In December 2015, we amended the Senior Secured Notes Purchase Agreement to pay an additional 0.5% per year in interest if our leverage ratio exceeds 4.25 to 1 plus an additional 0.5% if our leverage ratio exceeds 4.50 to 1. On August 2, 2017, we amended the Senior Secured Notes Purchase Agreement with an effective date of June 2, 2017. The amendment, among other things, conforms the financial covenants to match the amended terms of the Credit Agreement and provides for an increase in interest charged if our leverage ratio exceeds certain predetermined levels. In addition, the amendment also restricts us from increasing our distribution rate over the amount paid in the preceding quarter if our interest coverage ratio is less than 3.00 to 1. The Senior Secured Notes were secured by substantially all of our assets and rank equal in priority with borrowings under the Credit Agreement.

Repurchases

On December 29, 2017, we repurchased all of the remaining outstanding Senior Secured Notes. The following table summarizes repurchases of Senior Secured Notes for the period indicated:

	Year Ended

	March 31, 2018
Senior Secured Notes	
Notes repurchased	$230,500
Cash paid (excluding payments of accrued interest)	$250,179
Loss on early extinguishment of debt (1)	$(23,971)

(1) Loss on the early extinguishment of debt for the Senior Secured Notes during the year ended March 31, 2018 is inclusive of the write-off of debt issuance costs of $4.3 million. The loss is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

Prior to the December 29, 2017 repurchase of all the remaining outstanding Senior Secured Notes, we made a semi-annual principal installment payment of $19.5 million on December 19, 2017.

Senior Unsecured Notes

The senior unsecured notes include, as defined below, the 2019 Notes, 2021 Notes, 2023 Notes, and the 2025 Notes (collectively, the "Senior Unsecured Notes").

Issuances

On July 9, 2014, we issued $400.0 million of 5.125% Senior Notes Due 2019 (the "2019 Notes"). Interest is payable on January 15 and July 15 of each year. The registration of the 2019 Notes became effective January 13, 2015. The 2019 Notes mature on July 15, 2019.

On October 16, 2013, we issued $450.0 million of 6.875% Senior Notes Due 2021 (the "2021 Notes"). Interest is payable on April 15 and October 15 of each year. The registration of the 2021 Notes became effective on January 13, 2015. The 2021 Notes mature on October 15, 2021.

On October 24, 2016, we issued $700.0 million of 7.50% Senior Notes Due 2023 (the "2023 Notes"). Interest is payable on May 1 and November 1 of each year. The 2023 Notes mature on November 1, 2023.

On February 22, 2017, we issued $500.0 million of 6.125% Senior Notes Due 2025 (the"2025 Notes"). Interest is payable on March 1 and September 1 of each year. The 2025 Notes mature on March 1, 2025.

We have the right to redeem all Senior Unsecured Notes before 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 Senior Unsecured Notes, and the obligations under the Senior Unsecured Notes are fully and unconditionally 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 indentures governing the Senior Unsecured Notes contain various customary covenants, including, (i) pay distributions on, purchase or redeem our common equity or purchase or redeem our subordinated debt, (ii) incur or guarantee additional indebtedness or issue preferred units, (iii) create or incur certain liens, (iv) enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us, (v) consolidate, merge or transfer all or substantially all of our assets, and (vi) engage in transactions with affiliates.

Our obligations under the Senior Unsecured Notes 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.

Registration Rights

In connection with the issuance of the 2023 Notes and the 2025 Notes, we entered into a registration rights agreement in which we agreed to file a registration statement with the Securities and Exchange Commission ("SEC") so that the holders can exchange the 2023 Notes and the 2025 Notes for registered notes that have substantially identical terms as the 2023 Notes and the 2025 Notes and evidence the same indebtedness of the 2023 Notes and the 2025 Notes. In addition, the subsidiary guarantors agreed to exchange the guarantee related to the 2023 Notes and the 2025 Notes for a registered guarantee having substantially the same terms as the original guarantee. We filed a registration statement for both the 2023 Notes and the 2025 Notes, and the related guarantees, with the SEC which became effective on July 11, 2017 and 99.98% of the 2023 Notes and 99.98% of the 2025 Notes were exchanged on August 8, 2017.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Repurchases

The following table summarizes repurchases of Senior Unsecured Notes for the periods indicated:

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
2019 Notes			
Notes repurchased	$26,034	$9,009	$11,533
Cash paid (excluding payments of accrued interest)	$26,002	$7,099	$6,972
(Loss) gain on early extinguishment of debt (1)	$(140)	$1,759	$4,483
2021 Notes			
Notes repurchased	$—	$21,241	$61,711
Cash paid (excluding payments of accrued interest)	$—	$14,094	$36,449
Gain on early extinguishment of debt (2)	$—	$6,748	$24,049
2023 Notes			
Notes repurchased	$84,053	$—	$—
Cash paid (excluding payments of accrued interest)	$83,967	$—	$—
Loss on early extinguishment of debt (3)	$(1,136)	$—	$—
2025 Notes			
Notes repurchased	$110,865	$—	$—
Cash paid (excluding payments of accrued interest)	$107,050	$—	$—
Gain on early extinguishment of debt (4)	$2,046	$—	$—

(1) (Loss) gain on the early extinguishment of debt for the 2019 Notes during the years ended March 31, 2018, 2017 and 2016 is inclusive of the write off of debt issuance costs of $0.2 million, $0.2 million and $0.1 million, respectively. The (loss) gain is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

(2) Gain on the early extinguishment of debt for the 2021 Notes during the years ended March 31, 2017 and 2016 is inclusive of the write off of debt issuance costs of $0.4 million and $1.2 million, respectively. The gain is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

(3) Loss on the early extinguishment of debt for the 2023 Notes during the year ended March 31, 2018 is inclusive of the write off of debt issuance costs of $1.2 million. The loss is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

(4) Gain on the early extinguishment of debt for the 2025 Notes during the year ended March 31, 2018 is inclusive of the write off of debt issuance costs of $1.8 million. The gain is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

Compliance

At March 31, 2018, we were in compliance with the covenants under all of the Senior Unsecured Notes indentures.

Other Long-Term Debt

We have executed various non-interest bearing notes payable, primarily related to non-compete agreements entered into in connection with acquisitions of businesses. These instruments have an aggregate principal balance of $5.3 million at March 31, 2018, and the implied interest rates on these instruments range from 1.91% to 7.00% per year. We also have certain notes payable related to equipment financing. These instruments have an aggregate principal balance of $6.1 million at March 31, 2018, and the interest rates on these instruments range from 4.13% to 7.10% per year. Equipment loans totaling $41.7 million were paid off on March 30, 2017, resulting in a loss on the early extinguishment of debt of $1.6 million, which was net of $0.1 million of debt issuance costs and $1.5 million of prepayment penalties. The loss is reported within (loss) gain on early extinguishment of liabilities, net within our consolidated statement of operations.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Debt Maturity Schedule

The scheduled maturities of our long-term debt are as follows at March 31, 2018:

Year Ending March 31,	Revolving Credit Facility	Senior Unsecured Notes	Other Long-Term Debt	Total
	(in thousands)			
2019	$—	$—	$ 3,196	$3,196
2020	—	353,424	2,344	355,768
2021	—	—	5,484	5,484
2022	969,500	367,048	292	1,336,840
2023	—	—	81	81
Thereafter	—	1,005,082	18	1,005,100
Total	$969,500	$1,725,554	$ 11,415	$2,706,469

Note 9—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, is not expected to 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.

Environmental Matters

At March 31, 2018, we have an environmental liability, measured on an undiscounted basis, of $2.7 million, which is recorded within accrued expenses and other payables in our consolidated balance sheet. 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 we will not incur significant costs. 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 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.

As previously disclosed, the U.S. Environmental Protection Agency ("EPA") had informed NGL Crude Logistics, LLC, formerly known as Gavilon, LLC ("Gavilon Energy"), of alleged violations in 2011 by Gavilon Energy of the Clean Air Act's renewable fuel standards regulations (prior to its acquisition by us in December 2013). On October 4, 2016, the U.S. Department of Justice, acting at the request of the EPA, filed a civil complaint in the Northern District of Iowa against Gavilon Energy and one of its then suppliers, Western Dubuque Biodiesel LLC ("Western Dubuque"). Consistent with the earlier allegations by the EPA, the civil complaint related to transactions between Gavilon Energy and Western Dubuque and the generation of biodiesel renewable identification numbers ("RINs") sold by Western

Dubuque to Gavilon Energy in 2011. On December 19, 2016, we filed a motion to dismiss the complaint. On January 9, 2017, the EPA filed an amended complaint. The amended complaint seeks an order declaring Western Dubuque's RINs invalid and requiring the defendants to retire an equivalent number of valid RINs and that the defendants pay statutory civil penalties. On January 23, 2017, we filed a motion to dismiss the amended complaint, which was denied on May 24, 2017. On October 17, 2017, the EPA filed a motion for partial summary judgment against Gavilon Energy. Subsequently, we filed a motion for summary judgment and the EPA filed a second motion for partial summary judgment, none of which have yet been decided by the Court. The Court has set August 27, 2018 as the trial date for this matter. Consistent with our position against the previous EPA allegations, we deny the allegations in the amended civil complaint and that the EPA is entitled to summary judgment and we intend to continue vigorously defending ourselves in the civil action. However, at this time we are unable to determine the outcome of this action or its significance to us.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Asset Retirement Obligations

We have contractual and regulatory obligations at certain facilities for which we have to perform remediation, dismantlement, or removal activities when the assets are retired. Our liability for asset retirement obligations is discounted to present value. To calculate the liability, we make estimates and assumptions about the retirement cost and the timing of retirement. Changes in our assumptions and estimates may occur as a result of the passage of time and the occurrence of future events. The following table summarizes changes in our asset retirement obligation, which is reported within other noncurrent liabilities in our consolidated balance sheets (in thousands):

Balance at March 31, 2016	$5,574
Liabilities incurred	1,703
Liabilities assumed in acquisitions	406
Liabilities settled	(19)
Accretion expense	517
Balance at March 31, 2017	8,181
Liabilities incurred	592
Liabilities assumed in acquisitions	21
Liabilities settled	(549)
Accretion expense	888
Balance at March 31, 2018	$9,133

In addition to the obligations described above, we may be obligated to remove facilities or perform other remediation upon retirement of certain other assets. However, the fair value of the asset retirement obligation cannot currently be reasonably estimated because the settlement dates are indeterminable. We will record an asset retirement obligation for these assets in the periods in which settlement dates are reasonably determinable.

Operating Leases

We have executed various noncancelable operating lease agreements for product storage, office space, vehicles, real estate, railcars, and equipment. The following table summarizes future minimum lease payments under these agreements at March 31, 2018 (in thousands):

Year Ending March 31,	
2019	$132,861
2020	115,962
2021	99,312
2022	71,038
2023	53,273
Thereafter	50,061
Total	$522,507

Rental expense relating to operating leases was $125.1 million, $124.3 million, and $125.5 million during the years ended March 31, 2018, 2017 and 2016, respectively.

Pipeline Capacity Agreements

We have executed noncancelable agreements with crude oil pipeline operators, which guarantee us minimum monthly shipping capacity on the pipelines. As a result, we are required to pay the minimum shipping fees if actual shipments are less than our allotted capacity. Under certain agreements we have the ability to recover minimum shipping fees previously paid if our shipping volumes exceed the minimum monthly shipping commitment during each month remaining under the agreement, with some contracts containing provisions that allow us to continue shipping up to six months after the maturity date of the contract in order to recapture previously paid minimum shipping delinquency fees. We currently have an asset recorded in other noncurrent assets in our consolidated balance sheet for minimum shipping fees paid in both the current and previous periods that are expected to be recovered in future periods by exceeding the minimum monthly volumes (see Note 2).

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

The following table summarizes future minimum throughput payments under these agreements at March 31, 2018 (in thousands):

Year Ending March 31,	
2019	$50,201
2020	41,379
Total	$91,580

Construction Commitments

At March 31, 2018, we had construction commitments of $2.7 million.

Sales and Purchase Contracts

We have entered into product sales and purchase contracts for which we expect the parties to physically settle and deliver the inventory in future periods.

At March 31, 2018, we had the following commodity purchase commitments (in thousands):

	Crude Oil (1)		Natural Gas Liquids	
	Value	Volume (in barrels)	Value	Volume (in gallons)
Fixed-Price Commodity Purchase Commitments:				
2019	$77,015	1,230	$5,616	8,183
Index-Price Commodity Purchase Commitments:				
2019	$1,403,823	23,559	$502,428	582,456
2020	567,987	10,938	—	—
2021	453,328	9,330	—	—
2022	363,302	7,738	—	—
2023	256,327	5,482	—	—
Thereafter	191,010	4,112	—	—
Total	$3,235,777	61,159	$502,428	582,456

(1) Our crude oil index-price purchase commitments exceed our crude oil index-price sales commitments (presented below) due primarily to our long-term purchase commitments for crude oil that we purchase and ship on the Grand Mesa Pipeline. As these purchase commitments are deliver-or-pay contracts, we have not entered into corresponding long-term sales contracts for volumes we may not receive.

At March 31, 2018, we had the following commodity sale commitments (in thousands):

	Crude Oil		Natural Gas Liquids	
	Value	Volume (in barrels)	Value	Volume (in gallons)
Fixed-Price Commodity Sale Commitments:				
2019	$77,132	1,230	$26,140	30,917

2020	—	—	356	415
2021	—	—	28	30
Total	$77,132	1,230	$26,524	31,362
Index-Price Commodity Sale Commitments:				
2019	$1,261,876	20,262	$438,577	413,866
2020	94,660	1,599	2,022	2,253
Total	$1,356,536	21,861	$440,599	416,119

We account for the contracts shown in the tables above using the normal purchase and normal sale election. Under this accounting policy election, we do not record the contracts at fair value at each balance sheet date; instead, we record the purchase or sale at the contracted value once the delivery occurs. Contracts in the tables above may have offsetting derivative contracts (described in Note 11) 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 tables above. These contracts are included in the derivative disclosures in Note 11, and represent $48.8 million of our prepaid expenses and other current assets and $48.2 million of our accrued expenses and other payables at March 31, 2018.

Note 10—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. 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 is not required to guarantee or pay any of our debts or obligations.

General Partner Contributions

In connection with the issuance of common units for the vesting of restricted units and warrants that were exercised for common units during the year ended March 31, 2018, we issued 1,294 notional units to our general partner for less than $0.1 million in order to maintain its 0.1% interest in us.

In connection with the issuance of common units for the vesting of restricted units, ATM Program (as defined herein) and the equity issuance in February 2017, as discussed within this note, as well as common units issued for a retail propane acquisition during the year ended March 31, 2017, we issued 16,026 notional units to our general partner for $0.3 million in order to maintain its 0.1% interest in us.

Equity Issuances

On August 24, 2016, we entered into an equity distribution agreement in connection with an at-the-market program (the “ATM Program”) pursuant to which we may issue and sell up to $200.0 million of common units. This ATM Program is registered with the SEC on an effective registration statement on Form S-3. During the year ended March 31, 2017, we sold 3,321,135 common units for net proceeds of $64.4 million (net of offering costs of $0.9 million). As of March 31, 2018, approximately $134.7 million remained available for sale under the ATM Program.

On February 22, 2017, we completed a public offering of 10,120,000 common units. We received net proceeds of $222.5 million (net of offering costs of $11.8 million).

Common Unit Repurchase Programs

On August 29, 2017, the board of directors of our general partner authorized a common unit repurchase program, under which we may repurchase up to $15.0 million of our outstanding common units through December 31, 2017 from time to time in the open market or in other privately negotiated transactions. During the nine months ended December 31, 2017, we repurchased 1,516,848 common units for an aggregate price of $15.0 million, including commissions. This program ended on December 31, 2017.

On September 10, 2015, the board of directors of our general partner authorized a common unit repurchase program pursuant to which we could repurchase up to $45.0 million of our outstanding common units through March 31, 2016 from time to time in the open market or in other privately negotiated transactions. During the year ended March 31, 2016, we repurchased 1,623,804 common units for an aggregate price of $17.7 million. The program ended on March 31, 2016.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

Our Distributions

The following table summarizes distributions declared on our common units for the last three fiscal years:

Date Declared	Record Date	Date Paid	Amount Per Unit	Amount Paid to Limited Partners	Amount Paid to General Partner
				(in thousands)	
April 24, 2015	May 5, 2015	May 15, 2015	$0.6250	$59,651	$ 13,446
July 23, 2015	August 3, 2015	August 14, 2015	$0.6325	$66,248	$ 15,483
October 22, 2015	November 3, 2015	November 13, 2015	$0.6400	$67,313	$ 16,277
January 21, 2016	February 3, 2016	February 15, 2016	$0.6400	$67,310	$ 16,279
April 21, 2016	May 3, 2016	May 13, 2016	$0.3900	$40,626	$ 70
July 22, 2016	August 4, 2016	August 12, 2016	$0.3900	$41,146	$ 71
October 20, 2016	November 4, 2016	November 14, 2016	$0.3900	$41,907	$ 72
January 19, 2017	February 3, 2017	February 14, 2017	$0.3900	$42,923	$ 74
April 24, 2017	May 8, 2017	May 15, 2017	$0.3900	$46,870	$ 80
July 20, 2017	August 4, 2017	August 14, 2017	$0.3900	$47,460	$ 81
October 19, 2017	November 6, 2017	November 14, 2017	$0.3900	$47,000	$ 81
January 23, 2018	February 6, 2018	February 14, 2018	$0.3900	$47,223	$ 81
April 24, 2018	May 7, 2018	May 15, 2018	$0.3900	$47,374	$ 82

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
May 5, 2015	8,352,902
February 3, 2016	223,077

TLP’s Distributions

The following table summarizes distributions declared by TLP through February 1, 2016, the date TLP was deconsolidated:

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

Class A Convertible Preferred Units

On April 21, 2016, we entered into a private placement agreement to issue $200 million of 10.75% Class A Convertible Preferred Units (“Class A Preferred Units”) to Oaktree Capital Management L.P. and its co-investors

(“Oaktree”). On June 23, 2016, the private placement agreement was amended to increase the aggregate principal amount from $200 million to $240 million. We received net proceeds of $235.0 million (net of offering costs of $5.0 million) in connection with the issuance of 19,942,169 Class A Preferred Units and 4,375,112 warrants.

We pay a cumulative, quarterly distribution in arrears at an annual rate of 10.75% on the Class A Preferred Units, to the extent declared by the board of directors of our general partner. To the extent declared, such distributions will be paid for each such quarter within 45 days after each quarter end. The following table summarizes distributions declared on our Class A Preferred Units during the last two fiscal years:

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Notes to Consolidated Financial Statements (Continued)

Date Declared	Date Paid	Amount Paid to Class A Preferred Unitholders (in thousands)
July 22, 2016	August 12, 2016	$ 1,795
October 20, 2016	November 14, 2016	$ 6,449
January 19, 2017	February 14, 2017	$ 6,449
April 24, 2017	May 15, 2017	$ 6,449
July 20, 2017	August 14, 2017	$ 6,449
October 19, 2017	November 14, 2017	$ 6,449
January 23, 2018	February 14, 2018	$ 6,449
April 24, 2018	May 15, 2018	$ 6,449

If the Class A Preferred Unit quarterly distribution is not made in full in cash for any quarter, the Class A Preferred Unit distribution rate will increase by one quarter of a percentage point (0.25%) per year beginning with distributions for the first six-month period that a payment default is in effect, and will further increase by an additional one quarter of a percentage point (0.25%) beginning with distributions for the next six-month period during which a payment default remains in effect. The deficiency rate shall not exceed 11.25% per year; as long as the default is occurring, the amount of accrued but unpaid Class A Preferred Unit quarterly distributions shall increase at an annual rate of 10.75%, compounded quarterly, until paid in full.

The Class A Preferred Units have no mandatory redemption date but are redeemable, at our election, any time after the first anniversary of the closing date. We have the right to redeem all of the outstanding Class A Preferred Units at a price per Class A Preferred Unit equal to the purchase price multiplied by the redemption multiple then in effect. The redemption multiple means (a) 140% for redemptions occurring on or after the first, but prior to the second anniversary of the closing date, (b) 115% for redemptions occurring on or after the second, but prior to the third anniversary of the closing date, (c) 110% for redemptions occurring on or after the third, but prior to the eighth anniversary of the closing date and (d) 101% for redemptions occurring on or after the eighth anniversary of the closing date.

At any time after the third anniversary of the initial closing date, the Class A preferred unitholders shall have the right to convert all of the outstanding Class A Preferred Units at a price per Class A Preferred Unit equal to the purchase price multiplied by the conversion multiple then in effect, which may be settled in common units, cash or a combination, at our discretion. The conversion multiple means if our common units are trading at or above $12.035 (“the initial conversion price”), the conversion price is not adjusted. However, if the conversion price is less than the initial conversion price, the conversion price will be reset to the greater of (i) the adjusted volume weighted average price of our common units for the 15 trading days immediately preceding the third anniversary of the closing date or (ii) $5.00.

Upon a change of control of the Partnership, each Class A preferred unitholder shall have the right, at its election, to either (i) elect to have its Class A Preferred Units converted to common units; (ii) if we are the surviving entity of such change of control, it can elect to continue to hold its Class A Preferred Units; or (iii) require us to redeem its Class A Preferred Units for cash equal to (a) prior to the first anniversary of the closing date, 140% of the unit purchase price; (b) on or after the first but prior to the second anniversary of the closing date, 130% of the unit purchase price; (c) on or after the second anniversary of the closing date, 120% of the unit purchase price; and (d) thereafter, 101% of the unit purchase price. In each case, this amount will include any accrued but unpaid distributions at the redemption date.

Under the private placement agreement, we are required to file within 180 days of the initial closing date a registration statement registering the resales of common units issued or to be issued upon conversion of the Class A Preferred Units or exercise of the warrants and have the registration statement declared effective within 360 days after the closing date. We are required to continue to maintain the effectiveness of the registration statement until all securities have been sold. The Partnership's registration statement was declared effective by the SEC on November 23, 2016.

The warrants have an eight year term, after which unexercised warrants will expire. The holders of the warrants may exercise one-third of the warrants from and after the first anniversary of the original issue date, another one-third of the warrants from and after the second anniversary and the final one-third of the warrants from and after the third anniversary. Upon a change of control or in the event we exercise our redemption right with respect to the Class A Preferred Units, all unvested warrants shall immediately vest and be exercisable in full. The warrants have an exercise price of $0.01. During the year ended March 31, 2018, 607,653 warrants were exercised for common units and we received proceeds of less than $0.1 million. In addition, we repurchased 850,716 unvested warrants for a total purchase price of $10.5 million on June 23, 2017. As of March 31, 2018, 2,916,743 warrants were outstanding. On April 26, 2018, we repurchased outstanding warrants, as discussed further in Note 17, from funds managed by Oaktree, who are represented on the board of directors of our general partner.

We allocated the net proceeds on a relative fair value basis to the Class A Preferred Units ($186.4 million), which includes the value of a beneficial conversion feature, and warrants ($48.6 million). As discussed below, $131.5 million of the amount allocated to the Class A Preferred Units was allocated to the intrinsic value of the beneficial conversion feature. A beneficial conversion feature is defined as a nondetachable conversion feature that is in the money at the commitment date. Per the applicable accounting guidance, we are required to allocate a portion of the proceeds allocated to the Class A Preferred Units to the beneficial conversion feature based on the intrinsic value of the beneficial conversion feature. The intrinsic value is calculated at the commitment date based on the difference between the fair value of the common units at the issuance date (number of common units issuable at conversion multiplied by the per unit value of our common units at the issuance date) and the proceeds attributed to the Class A Preferred Units. We record the accretion attributable to the beneficial conversion feature as a deemed distribution using the effective interest method over the three year period prior to the effective dates of the holders' conversion right. Accretion for the beneficial conversion feature was $18.8 million and $9.0 million for the years ended March 31, 2018 and 2017, respectively.

As discussed above, the Class A Preferred Units are not mandatorily redeemable but are redeemable upon a change of control, which was not certain to occur at the issuance of the Class A Preferred Units. Due to the redemption being conditioned upon an event that is not certain to occur or that is not under our control, we are required to record the value allocated to the Class A Preferred Units, excluding the value of the beneficial conversion feature, between liabilities and equity (mezzanine or temporary equity) in our consolidated balance sheet. The value allocated to the warrants and the beneficial conversion feature was recorded within Limited Partners' equity in our consolidated balance sheet.

Class B Preferred Units

During the year ended March 31, 2018, we issued 8,400,000 of our 9.00% Class B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units ("Class B Preferred Units") representing limited partner interests at a price of $25.00 per unit for net proceeds of $202.7 million (net of the underwriters' discount of $6.6 million and offering costs of $0.7 million).

At any time on or after July 1, 2022, we may redeem our Class B Preferred Units, in whole or in part, at a redemption price of $25.00 per Class B Preferred Unit plus an amount equal to all accumulated and unpaid distributions to, but not including, the date of redemption, whether or not declared. We may also redeem the Class B Preferred Units upon a change of control as defined in our partnership agreement. If we choose not to redeem the Class B Preferred Units, the Class B preferred unitholders may have the ability to convert the Class B Preferred Units to common units at the then applicable conversion rate. Class B preferred unitholders have no voting rights except with respect to certain matters set forth in our partnership agreement.

Distributions on the Class B Preferred Units are payable on the 15th day of each January, April, July and October of each year to holders of record on the first day of each payment month. The initial distribution rate for the Class B Preferred Units from and including the date of original issue to, but not including, July 1, 2022 is 9.00% per year of the $25.00 liquidation preference per unit (equal to $2.25 per unit per year). On and after July 1, 2022, distributions on the Class B Preferred Units will accumulate at a percentage of the $25.00 liquidation preference equal to the applicable three-month LIBOR plus a spread of 7.213%.

The following table summarizes distributions declared on our Class B Preferred Units during the last fiscal year:

Date Declared	Record Date	Date Paid	Amount Paid to Class B Preferred Unitholders (in thousands)
September 18, 2017	September 29, 2017	October 16, 2017	$ 5,670
December 19, 2017	December 29, 2017	January 15, 2018	$ 4,725
March 19, 2018	April 2, 2018	April 16, 2018	$ 4,725

The distribution amount paid on April 16, 2018 is included in accrued expenses and other payables in our consolidated balance sheet at March 31, 2018.

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Notes to Consolidated Financial Statements (Continued)

Amended and Restated Partnership Agreement

On June 13, 2017, NGL Energy Holdings LLC executed the Fourth Amended and Restated Agreement of Limited Partnership. The preferences, rights, powers and duties of holders of the Class B Preferred Units are defined in the amended and restated partnership agreement. The Class B Preferred Units rank senior to the common units, with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up, and are on parity with the Class A Preferred Units. The Class B Preferred Units have no stated maturity but we may redeem the Class B Preferred Units at any time on or after July 1, 2022 or upon the occurrence of a change in control.

On June 24, 2016, NGL Energy Holdings LLC executed the Third Amended and Restated Agreement of Limited Partnership. The preferences, rights, powers and duties of holders of the Class A Preferred Units are defined in the amended and restated partnership agreement. The Class A Preferred Units rank senior to the common units, with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up. The Class A Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless redeemed by the Partnership or converted into common units at the election of the Partnership or the Class A preferred unitholders or in connection with a change of control.

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 upon a change of control, at the discretion of the board of directors of our general partner. No distributions accrue to or are paid on the restricted units during the vesting period.

The restricted units include both awards that: (i) vest contingent on the continued service of the recipients through the vesting date (the “Service Awards”) and (ii) vest 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”).

During the three months ended September 30, 2016, we changed our process for how taxes are withheld upon the vesting of restricted units. Previously, employees could choose to pay cash for their portion of the taxes or have us withhold enough units to meet their tax withholding requirements. Employees could also elect to have the units withheld to exceed the statutory minimums. Now, employees will still be able to pay cash to satisfy their tax obligation or they can elect to sell enough units, through a broker assisted cashless exercise program, to meet their tax obligation. As a result of this change in process, the unvested restricted units and future grants are eligible for equity classification. Prior to this change in process, we classified any Service Awards or Performance Awards granted as liabilities and were required to recalculate the fair value of the award at each reporting date. Awards classified as equity are valued only at their grant date and are not revalued at each reporting date.

On April 1, 2017, we made an accounting policy election to account for actual forfeitures, rather than estimate forfeitures each period (as previously required). As a result, the cumulative effect adjustment, which represents the differential between the amount of compensation expense previously recorded and the amount that would have been recorded without assuming forfeitures, had no impact on our consolidated financial statements.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

The following table summarizes the Service Award activity during the years ended March 31, 2018, 2017 and 2016:

Unvested Service Award units at March 31, 2015	2,260,400
Units granted	1,484,412
Units vested and issued	(844,626)
Units withheld for employee taxes	(464,054)
Units forfeited	(139,000)
Unvested Service Award units at March 31, 2016	2,297,132
Units granted	3,124,600
Units vested and issued	(2,350,082)
Units forfeited	(363,150)
Unvested Service Award units at March 31, 2017	2,708,500
Units granted	1,964,911
Units vested and issued	(2,260,011)
Units forfeited	(134,525)
Unvested Service Award units at March 31, 2018	2,278,875

In connection with the vesting of certain restricted units during year ended March 31, 2018, we canceled 57,498 of the newly-vested common units in satisfaction of $0.8 million of employee tax liability paid by us. Pursuant to the terms of the LTIP, these canceled units are available for future grants under the LTIP.

The following table summarizes the scheduled vesting of our unvested Service Award units at March 31, 2018:

Year Ending March 31,	Number of Units
2019	935,975
2020	969,475
2021	373,425
Total	2,278,875

Service Awards are valued at the closing price as of the grant date less the present value of the expected distribution stream over the vesting period using a risk-free interest rate. We record the expense for each Service Award on a straight-line basis over the requisite period for the entire award (that is, over the requisite service period of the last separately vesting portion of the award), ensuring that the amount of compensation cost recognized at any date at least equals the portion of the grant-date value of the award that is vested at that date.

In December 2017, the compensation committee of the board of directors of our general partner decided that the vesting of all future grants would be split so that half of the award will vest in February and the other half will vest in November instead of the entire grant vesting in July, which was the month the units generally vested. In addition, employees with unvested Service Awards were given an option to switch the vesting of their outstanding Service Awards and split the awards to vest in February and November or keep the vesting in July. For example, if an employee elected to change the vesting of their outstanding Service Awards, an award that was originally scheduled to vest in July 2018 would now be split so that half of the award will vest in February 2018 and the other half in November 2018. The Service Awards of individuals that elected to split the vesting are considered to be modified. The impact of the modification was not material to the current or future unit based compensation expense.

During the years ended March 31, 2018, 2017 and 2016, we recorded compensation expense related to Service Award units of $16.2 million, $56.2 million and $35.2 million, respectively.

Of the restricted units granted and vested during the year ended March 31, 2018, 964,702 units were granted as a bonus for performance during the fiscal year ended March 31, 2017. The total amount of these bonus payments was $12.4 million, of which we had accrued $5.5 million as of March 31, 2017. Also, 59,393 units were granted and vested as incentive compensation for the fiscal year ended March 31, 2018. The value of these awards was $0.7 million and was recorded within general and administrative expense in our consolidated statement of operations for the year ended March 31, 2018.

Of the restricted units granted and vested during the year ended March 31, 2017, 1,008,091 units were granted as a bonus for performance during the year ended March 31, 2016. We accrued expense of $16.8 million during the year ended

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

March 31, 2016 as an estimate of the value of such bonus units that would be granted. During the year ended March 31, 2017, we recorded an additional $2.2 million to true up the estimate to the $19.0 million of actual expense associated with these bonuses. Since the units were not granted until August 2016, the full $19.0 million is reflected in the expense during the year ended March 31, 2017.

The following table summarizes the estimated future expense we expect to record on the unvested Service Award units at March 31, 2018 (in thousands):

Year Ending March 31,	
2019	$12,473
2020	6,644
2021	2,081
Total	$21,198

During April 2015, our general partner granted Performance Award units to certain employees. 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. As of March 31, 2018, performance will be measured over the following periods:

Vesting Date of Tranche	Performance Period for Tranche
July 1, 2018	July 1, 2015 through June 30, 2018
July 1, 2019	July 1, 2016 through June 30, 2019
July 1, 2020	July 1, 2017 through June 30, 2020

The following table summarizes the percentage of the maximum Performance Award units that will vest depending on the percentage of entities in the Index that NGL outperforms:

Our Relative Total Unitholder Return Percentile Ranking	Payout (% of Target Units)
Less than 50th percentile	0%
Between the 50th and 75th percentile	50%–100%
Between the 75th and 90th percentile	100%–200%
Above the 90th percentile	200%

The following table summarizes the Performance Award activity during the years ended March 31, 2018, 2017 and 2016:

Unvested Performance Award units at March 31, 2015	—
Units granted	1,041,073
Units vested and issued	(349,691)
Units forfeited	(54,000)
Unvested Performance Award units at March 31, 2016	637,382
Units granted	932,309
Units forfeited	(380,691)
Unvested Performance Award units at March 31, 2017	1,189,000
Units granted	224,000
Units forfeited	(496,000)
Unvested Performance Award units at March 31, 2018	917,000

During the July 1, 2014 through June 30, 2017 performance period, the return on our common units was below the return of the 50th percentile of our peer companies in the Index. As a result, no Performance Award units vested on July 1, 2017 and performance units with the July 1, 2017 vesting date are considered to be forfeited.

The fair value of the Performance Awards is estimated using a Monte Carlo simulation at the grant date. The significant inputs used to calculate the fair value of these awards include (i) the price per our common units at the grant date

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

and the beginning of the performance period, (ii) a compounded risk-free interest rate, (iii) our compounded dividend yield, (iv) our historical volatility, (v) the volatility and correlations of our peers and (vi) the remaining performance period. We record the expense for each of the tranches of the Performance Awards on a straight-line basis over the period beginning with the grant date and ending with the vesting date of the tranche. Any Performance Awards that do not become earned Performance Awards will terminate, expire and otherwise be forfeited by the participants. During the years ended March 31, 2018, 2017 and 2016, we recorded compensation expense related to Performance Award units of $5.3 million, $7.2 million and $16.4 million, respectively.

The following table summarizes the estimated future expense we expect to record on the unvested Performance Award units at March 31, 2018 (in thousands):

Year Ending March 31,	
2019	$4,200
2020	1,987
2021	406
Total	$6,593

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. 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, 2018, approximately 1.3 million common units remain available for issuance under the LTIP.

Note 11—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 the dates indicated:

	March 31, 2018		March 31, 2017	
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
	(in thousands)			
Level 1 measurements	$5,093	$(20,186)	$2,590	$(21,113)
Level 2 measurements	48,752	(54,410)	38,729	(27,799)
	53,845	(74,596)	41,319	(48,912)
Netting of counterparty contracts (1)	(2,922)	2,922	(1,508)	1,508
Net cash collateral (held) provided	(1,762)	17,263	(1,035)	19,604
Commodity derivatives	$49,161	$(54,411)	$38,776	$(27,800)

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

The following table summarizes the accounts that include our commodity derivative assets and liabilities in our consolidated balance sheets at the dates indicated:

	March 31, 2018	March 31, 2017
	(in thousands)	
Prepaid expenses and other current assets	$49,161	$38,711
Other noncurrent assets	—	65
Accrued expenses and other payables	(51,039)	(27,622)
Other noncurrent liabilities	(3,372)	(178)
Net commodity derivative (liability) asset	$(5,250)	$10,976

The following table summarizes our open commodity derivative contract positions at the dates indicated. We do not account for these derivatives as hedges.

Contracts	Settlement Period	Net Long (Short) Notional Units (in barrels)	Fair Value of Net Assets (Liabilities)
		(in thousands)	
At March 31, 2018:			
Cross-commodity (1)	April 2018–March 2019	155	$ (430)
Crude oil fixed-price (2)	April 2018–December 2019	(1,376)	(8,960)
Crude oil index (2)	April 2018–April 2018	(10)	(6)
Propane fixed-price (2)	April 2018–February 2019	14	1,849
Refined products fixed-price (2)	April 2018–January 2020	(5,419)	(17,081)
Refined products index (2)	April 2018–April 2018	(4)	(17)
Other	April 2018–March 2022		3,894
			(20,751)
Net cash collateral provided			15,501
Net commodity derivative liability			$ (5,250)
At March 31, 2017:			
Crude oil fixed-price (2)	April 2017–May 2017	(800)	$ (55)
Propane fixed-price (2)	April 2017–December 2018	220	1,082
Refined products fixed-price (2)	April 2017–January 2019	(4,682)	(7,729)
Refined products index (2)	April 2017–December 2017	(18)	(103)
Other	April 2017–March 2022		(788)
			(7,593)
Net cash collateral provided			18,569
Net commodity derivative asset			$ 10,976

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

(2) We may have fixed price physical purchases, including inventory, offset by floating price physical sales or floating price physical purchases offset by fixed price physical sales. These contracts are 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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The following table summarizes the net (losses) gains recorded from our commodity derivatives to cost of sales in our consolidated statements of operations for the periods indicated (in thousands):

Year Ended March 31,	
2018	$(116,878)
2017	$(56,356)
2016	$103,223

Credit Risk

We have credit policies 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 industry standard master netting agreements, which allow for offsetting counterparty receivable and payable balances for certain transactions. At March 31, 2018, our primary counterparties were retailers, resellers, energy marketers, producers, refiners, and dealers. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, as the counterparties may be similarly affected by changes in economic, regulatory or other conditions. If a counterparty does not perform on a contract, we may not 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, 2018, we had $969.5 million of outstanding borrowings under our Revolving Credit Facility at a weighted average interest rate of 4.99%.

Fair Value of Fixed-Rate Notes

The following table provides fair values estimates of our fixed-rate notes at March 31, 2018 (in thousands):

Senior Unsecured Notes:	
2019 Notes	$353,208
2021 Notes	$366,819
2023 Notes	$618,072
2025 Notes	$370,651

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

Note 12—Segments

The following table summarizes certain financial data related to our segments. Transactions between segments are recorded based on prices negotiated between the segments.

The "Corporate and Other" category in the table below includes certain corporate expenses that are not allocated to the reportable segments.

NGL ENERGY PARTNERS LP AND SUBSIDIARIES
Notes to Consolidated Financial Statements (Continued)

	Year Ended March 31,		
	2018	2017	2016
	(in thousands)		
Revenues:			
Crude Oil Logistics:			
Crude oil sales	$2,151,203	$1,603,667	$3,170,891
Crude oil transportation and other	122,786	70,027	55,882
Elimination of intersegment sales	(13,914)	(6,810)	(9,694)
Total Crude Oil Logistics revenues	2,260,075	1,666,884	3,217,079
Water Solutions:			
Service fees	149,114	110,049	136,710
Recovered hydrocarbons	58,948	31,103	41,090
Other revenues	21,077	18,449	7,201
Total Water Solutions revenues	229,139	159,601	185,001
Liquids:			
Propane sales	1,203,486	807,172	618,919
Butane sales	562,066	391,265	317,994
Other product sales	432,570	308,031	302,181
Other revenues	22,548	32,648	35,943
Elimination of intersegment sales	(150,655)	(100,028)	