Marlin Midstream Partners, LP
Form 10-K
March 12, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark one)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-36018
MARLIN MIDSTREAM PARTNERS, LP
(Exact name of registrant as specified in its charter)

Delaware	46-2627595
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
12377 Merit Drive Suite 300, Dallas, Texas 75251	75251
(Address of principal executive offices)	(Zip Code)

(972) 674-5200
(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	The NASDAQ Global Market

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No þ
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ
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 þ No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 þ No ¨
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. þ
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ¨ Accelerated filer þ
Non-accelerated filer ¨ (Do not check if smaller reporting company) Smaller reporting company ¨

Indicate by a check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ¨ No þ
The aggregate market value of the Partnership's common units representing limited partner interest held by non-affiliates of the registrant was approximately $139,975,000 on June 30, 2014, based on the closing price as reported on NASDAQ Global Market.
There were 17,723,793 limited partner units outstanding as of February 27, 2015.

MARLIN MIDSTREAM PARTNERS, LP
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For the Year Ended December 31, 2014

GLOSSARY OF TERMS

The following are definitions of certain terms used in this Annual Report on Form 10-K:

Bbls: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.
Bbls/d: Stock tank barrel per day.
Bbls/hr: Stock tank barrel per hour.
Condensate: A natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.
Crude oil: A mixture of hydrocarbons that exists in liquid phase in underground reservoirs.
Dry gas: A natural gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.
End-user markets: The ultimate users and consumers of transported energy products.
EUR: Estimated ultimate recovery
Mcf: One thousand cubic feet.
MMBtu: One million British Thermal Units.
MMcf: One million cubic feet.
MMcf/d: One million cubic feet per day.
Natural gas liquids, or NGLs: The combination of ethane, propane, normal butane, isobutane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
Residue gas: The dry gas remaining after being processed or treated.
Tailgate: Refers to the point at which processed natural gas and natural gas liquids leave a processing facility for end-user markets.
Throughput: The volume of natural gas transported or passing through a pipeline, plant, terminal or other facility during a particular period.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We have made in this report, and may from time to time otherwise make in other public filings, press releases and discussions by management, forward-looking statements concerning our operations, economic performance and financial condition. These statements can be identified by the use of forward-looking terminology including “may,” “will,” “believe,” “expect,” “anticipate,” “estimate,” “continue,” or other similar words. These statements discuss future expectations, contain projections of results of operations or financial condition or include other “forward-looking” information. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will be realized.

These forward-looking statements involve risks and uncertainties. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

- the volume of natural gas we gather and process and the volume of NGLs we transport;
- the volume of crude oil that we transload;
- the level of production of crude oil and natural gas and the resultant market prices of crude oil, natural gas and NGLs;
- the level of competition from other midstream natural gas companies and crude oil logistics companies in our geographic markets and industry;
- the level of our operating expenses;
- regulatory action affecting the supply of, or demand for, crude oil and natural gas, the transportation rates we can charge on our pipelines, how we contract for services, our existing contracts, our operating costs and our operating flexibility;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation;
- capacity charges and volumetric fees that we pay for NGL fractionation services;
- realized pricing impacts on our revenues and expenses that are directly subject to commodity price exposure;
- the creditworthiness and performance of our customers, suppliers and contract counterparties, and any material nonpayment or non-performance by one or more of these parties;
- damage to pipelines, facilities, plants, related equipment and surrounding properties, including damage to third party pipelines or facilities upon which we rely for transportation services, caused by hurricanes, earthquakes, floods, fires, severe weather, casualty losses, explosions and other natural disasters and acts of terrorism;
- outages at the processing or fractionation facilities owned by us or third parties caused by mechanical failure and maintenance, construction and other similar activities;
- actions taken by third-party operators, processors and transporters;
- leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise;
- the level and timing of our expansion capital expenditures and our maintenance capital expenditures;
- the cost of acquisitions, if any;
- the level of our general and administrative expenses, including reimbursements to our general partner and its affiliates for services provided to us;
- our level of indebtedness, debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner;
- other business risks affecting our cash levels; and
- other factors discussed below and elsewhere in this Annual Report on Form 10-K and in our other public filings and press releases.

The risk factors and other factors noted throughout or incorporated by reference in this report could cause our actual results to differ materially from those contained in any forward-looking statement. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Items 1 and 2. Business and Properties
GENERAL OVERVIEW

Marlin Midstream Partners, LP is a Delaware limited partnership (the "Partnership") formed in April 2013 by NuDevco Partners, LLC and its affiliates ("NuDevco") to develop, own, operate and acquire midstream energy assets. Through our wholly owned subsidiaries, Marlin Logistics, LLC ("Marlin Logistics") and Marlin Midstream, LLC ("Marlin Midstream"), we generate revenues by charging fees for gathering, transporting, treating and processing natural gas, transloading crude oil and selling or delivering NGLs to third parties.
As of December 31, 2014, NuDevco owned and controlled our general partner, Marlin Midstream GP, LLC (our "general partner"). NuDevco is wholly owned by W. Keith Maxwell III. In July 2013, we completed our initial public offering (the "IPO") of 6,875,000 common units to the public for $20.00 per common unit. In exchange for NuDevco contributing Marlin Logistics and Marlin Midstream to us, we issued 1,849,545 common units and all of the Partnership's subordinated units and incentive distribution rights to wholly owned subsidiaries of NuDevco. At December 31, 2014, common units held by public security holders represent 39.8% of our outstanding limited partner interests, and NuDevco held 60.2% of our outstanding limited partner interests. Please see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-Initial Public Offering."
The information in this report contains information occurring prior to the completion of our initial public offering on July 31, 2013, and prior to the effective dates of certain of the agreements discussed herein. Consequently, the combined financial statements and related discussion of financial condition and results of operations contained in this report for those periods prior to the initial public offering pertain to the combined businesses and assets of Marlin Midstream and Marlin Logistics.
On February 27, 2015, we completed transactions (the "Transactions"), described in detail below, pursuant to a Transaction Agreement, dated January 14, 2015 (the "Transaction Agreement"), by and among us, Azure Midstream Energy LLC, a Delaware limited liability company ("Azure"), the general partner, NuDevco and Marlin IDR Holdings, LLC, a Delaware limited liability company and wholly-owned subsidiary of NuDevco ("IDRH"). Pursuant to the Transaction Agreement, we acquired the Legacy gathering system (the "Legacy System") from Azure and Azure acquired all of the equity interests in our general partner and 90% of our IDR Units (as defined below) from NuDevco.

The following transactions were consummated on February 27, 2015, in connection with the closing of the Transactions (the "Closing"):

- we amended and restated our partnership agreement to reflect the unitization of all of our incentive distribution rights (as unitized, the "IDR Units") and recapitalized the incentive distribution rights owned by IDRH into 100 IDR Units;

- we redeemed 90 IDR Units held by IDRH in exchange for a payment by us of $63 million to IDRH (the "Redemption");

- we acquired the Legacy System from Azure through the contribution, indirectly or directly, of (i) all of the outstanding general and limited partner interests in Talco Midstream Assets, Ltd., a Texas limited liability company and subsidiary of Azure, and (ii) certain assets owned by TGG Pipeline, Ltd., a Texas limited liability company and subsidiary of Azure, in exchange for aggregate consideration of $162.5 million, which was paid to Azure in the form of $99.5 million in cash and by the issuance of 90 IDR Units (the foregoing transaction, collectively, the "Contribution"); and

- Azure purchased from NuDevco (i) all of the outstanding membership interests in our general partner and (ii) an option to acquire up to 20% of each of the common units and subordinated units held by NuDevco as of the execution date of the Transaction Agreement.

Following the consummation of the Transactions, Azure controls us through its ownership of all of the equity interests in our general partner. Our general partner controls us through its ownership of our outstanding general partner units, which represents an approximate 2% economic general partner interest in us. Azure also owns 90 IDR Units, which represent 90% of our IDR Units. NuDevco owns approximately 60.2% of our outstanding limited partner interest and 10 IDR Units, which represent 10% of our IDR Units.

Azure is a midstream company with a focus on owning, operating, developing and acquiring midstream energy infrastructure in core producing areas in the United States. Azure currently provides natural gas gathering, compression, treating and processing services in northern Louisiana and east Texas in the prolific Haynesville and Bossier Shale formations.

Unless the context otherwise requires, references in this Annual Report on Form 10-K to “we,” “our,” “us,” or like terms, when used in a historical context, refer to the combined businesses and assets of Marlin Midstream and Marlin Logistics, and when used in the present tense or prospectively, refer to the Partnership and its subsidiaries.

Available information. We file our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other documents electronically with the U.S. Securities and Exchange Commission (“SEC”) under the Securities Exchange Act of 1934, as amended. From time to time, we may also file registration and related statements pertaining to equity or debt offerings.

We provide access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing with the SEC, on our Internet site located at www.marlinmidstream.com. The public may also read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, N.E., Room 1580, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The public may also obtain such reports from the SEC’s Internet website at www.sec.gov.

Our Corporate Governance Guidelines, Code of Business Conduct and Ethics and the charters of the audit committee and the conflicts committee of our general partner’s board of directors are also available on our Internet website. We will also provide, free of charge, a copy of any of our governance documents listed above upon written request to our general partner’s corporate secretary at our principal executive office. Our principal executive offices are located at 12377 Merit Drive, Dallas, Texas, 75251. Our telephone number is (972) 674-5200.

OUR ASSETS AND AREAS OF OPERATION

Overview

We are a fee-based, growth-oriented Delaware limited partnership formed to develop, own, operate and acquire midstream energy assets. We currently provide natural gas gathering, compression, dehydration, treating, processing and hydrocarbon dew-point control and transportation services, which we refer to as our midstream natural gas business, and crude oil transloading services, which we refer to as our crude oil logistics business. Our assets and operations are organized into the Midstream Natural Gas Segment and the Logistics Segment.

For additional information relating to revenues, profits and total assets by operating segment, please see Note 9 “Segment Information” to our Consolidated Financial Statements included in this Annual Report on Form 10-K.

Midstream Natural Gas Segment. As of December 31, 2014, our midstream natural gas segment primarily consisted of the following assets: (i) two related natural gas processing plants located in Panola County, Texas, (ii) a natural gas processing plant located in Tyler County, Texas, (iii) two natural gas gathering systems connected to our Panola County processing plants, and (iv) two NGL transportation pipelines that connect our Panola County and Tyler County processing plants to third party NGL pipelines. Our primary midstream natural gas assets are located in long-lived oil and natural gas producing regions in East Texas and gather and process NGL-rich natural gas streams associated with production primarily from the Cotton Valley Sands, Haynesville Shale, Austin Chalk and Eaglebine formations.

Subsequent to December 31, 2014, we acquired the Legacy System, and the results of operations of the Legacy System will be included within our midstream natural gas segment. The addition of the Legacy System provides us with access to producing acreage that is currently not directly accessible within Harrison, Panola and Rusk counties in Texas. For a more detailed description of the Legacy System, see “Legacy Gathering System” below.

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The following table sets forth information about our primary midstream natural gas assets, as of and for the year ended December 31, 2014 (other than our Legacy System, which was acquired in February 2015:

Midstream Natural Gas	System Type	County, State	Miles	Gas Compression (bhp)	Approximate Design Capacity (MMcf/d except as otherwise noted)
Panola 1	Processing	Panola, Texas		8,220	100
Panola 2	Processing	Panola, Texas		10,400	120
Total Panola			N/A	18,620	220
Tyler (1)	Processing	Tyler, Texas	N/A	4,640	80
Lake Murvaul	Natural Gas Gathering	Panola and Harrison Counties, Texas	54	6,300	100
Oak Hill Lateral	Natural Gas Gathering	Panola and Harrison Counties, Texas	11	N/A	100
Turkey Creek (Bbls/d)	NGL Pipelines	Panola and Tyler Counties, Texas	13	N/A	20,000
Legacy Gathering System (2)	Natural Gas Gathering	Panola, Harrison and Rusk Counties, Texas and Caddo parish Louisiana	658	14,125	500

(1) The Tyler processing facility includes three 40 MMcf/d cryogenic trains that are currently operational while two 20 MMcf/d cryogenic trains are currently idle.

(2) The Legacy Gathering System was acquired on February 27, 2015 in connection with the closing of the Transactions, and is currently operational.

Panola County Processing Plants

Our Panola County processing plants are situated northeast of the town of Carthage in East Texas on approximately 35 acres. These plants process NGL-rich natural gas from the Haynesville Shale and Cotton Valley natural gas production areas, which are areas known for their long-lived reserves. These plants are natural gas treating and cryogenic processing plants that include residue gas compression, amine treating and glycol dehydration equipment with current design capacity to process up to 220 MMcf/d of natural gas.

Our processing plants in Panola County, which we refer to as our Panola 1 and Panola 2 processing plants, are operational as a single integrated facility, with common inlet and outlet points. Our Panola County plants have the following characteristics:

- Our Panola 1 processing plant consists of a cryogenic gas processing plant with a nameplate capacity of 100 MMcf/d, one 225 GPM amine treating unit and five dedicated compressor units with an aggregate of 8,220 bhp of residue gas compression; and
- Our Panola 2 processing plant consists of a cryogenic gas processing plant with a nameplate capacity of 120 MMcf/d, one 320 GPM amine treating unit and six dedicated compressor units with an aggregate of 10,400 bhp of residue gas compression.

Inlet volumes at our Panola County plants are obtained from numerous sources with various natural gas compositions. Supply interconnects to the facility include nine pipelines extending from our Lake Murvaul gathering system, our Oak Hill Lateral, Atmos Energy Corporation's ("Atmos Energy") S2 pipeline, Kinder Morgan's McCormick pipeline, Texas Gas Gathering's ("TGG") Harrison and Panola County gathering systems and MarkWest Energy Partners, L.P.'s ("MarkWest") pipeline. Residue gas from our Panola County plants is delivered to several pipelines, including the Texas Gas, CenterPoint CP, Tennessee Gas and Gulf South Pipeline, LP ("Gulf South") pipelines, and the DCP Carthage trading hub through the Atmos Energy and Enterprise pipelines. NGL production from our Panola County plants is delivered into one of our Turkey Creek pipelines, which extends to TEPPCO Partners, L.P.'s Panola Pipeline for redelivery to the Enterprise fractionation facilities at the Mont Belvieu, Texas trading hub.

Tyler County Gas Processing Plant

Our Tyler County processing facility is situated northeast of the town of Woodville in East Texas on approximately ten acres. This facility processes NGL-rich natural gas from the Austin Chalk and Eaglebine natural gas production formations, which are areas known for their long- lived reserves. This facility consists of natural gas treating and cryogenic processing plants that include residue gas compression, amine treating, and glycol dehydration equipment with a design capacity to process up to 80 MMcf/d of natural gas.

Our Tyler County processing plant includes one cryogenic processing train with nameplate capacity of 40 MMcf/d, two 20 MMcf/d cryogenic processing trains with aggregate nameplate capacity of 40 MMcf/d, both of which are currently idle, two 40 MMcf/d glycol dehydration units and two 200 GPM amine units. Our Tyler County processing facility currently utilizes three compressor units with an aggregate of 4,640 bhp of residue gas compression.

We do not own or operate any natural gas gathering systems associated with our Tyler County processing plant. The facility receives all of its natural gas from a gathering system owned and operated by Anadarko and delivers residue gas through an interconnect with the Tennessee Gas Pipeline Company pipeline. To the extent we are not using the full capacity of our Tyler County processing plant to process Anadarko's gas, we believe we would be able to access volumes from other producers to the extent we are able to construct new, or tie into existing third- party gathering systems. NGLs produced by our Tyler County processing plant are stored in two 30,000 gallon surge tanks and one 12,000 gallon surge tank and transported through one of our Turkey Creek NGL pipelines to an NGL pipeline owned by West Texas LPG Pipeline Limited Partnership for delivery to the Enterprise fractionator at the Mont Belvieu trading hub.

Lake Murvaul Gathering System

Our Lake Murvaul natural gas gathering system is connected to our Panola County processing plants and gathers natural gas primarily from delivery points on our gathering systems and interconnecting pipelines in the area. NuDevco and its affiliates purchased the original Lake Murvaul gathering system, consisting solely of a 12-inch trunk line extending approximately 10 miles southwest from the site of our Panola County processing plants, from CenterPoint Energy. The gathering system currently consists of approximately 31 miles of 12-inch trunk line, approximately 23 miles of 4-inch, 6-inch and 8-inch gathering lines and seven compressor stations with total compression of approximately 6,300 bhp. The gathering system has an aggregate capacity of approximately 100 MMcf/d.

Our Lake Murvaul gathering system has pipeline interconnects with Gulf South, Texas Eastern Transmission, LP, ETC Gas Company Ltd., Natural Gas Pipeline Company of America LLC and DCP Midstream Partners, LP ("DCP Midstream"). Producers generally bear the cost of connecting their wells to our system at delivery points on our gathering systems.

Oak Hill Lateral

Our Oak Hill Lateral, which was placed into service in March 2013, is connected to our Panola County processing plant and gathers natural gas through a connection to a gathering system owned by Anadarko. Our Oak Hill Lateral consists of approximately 11 miles of 12-inch trunk line with a current capacity of approximately 100 MMcf/d.

Turkey Creek NGL Pipelines

Our wholly owned subsidiary, Turkey Creek Pipeline, LLC, owns and operates the following two NGL pipelines, which we refer to as our Turkey Creek pipelines:

- a 4-inch diameter y-grade NGL pipeline with a total capacity of 10,000 Bbls/d (expandable to 15,000 Bbls/d) extending approximately two miles from our Panola County processing plants to a pipeline owned by TEPPCO Partners, L.P. for redelivery to the Enterprise fractionator in Mont Belvieu; and
- a 6-inch diameter y-grade NGL pipeline with a total capacity of 10,000 Bbls/d extending approximately 11 miles from our Tyler County processing plants to an NGL pipeline owned by West Texas LPG Pipeline Limited Partnership for redelivery to the Enterprise fractionator in Mont Belvieu.

Legacy Gathering System

The Legacy system was contributed to us as part of the Transactions on February 27, 2015. The Legacy System is primarily located within Harrison, Panola and Rusk counties in Texas and Caddo parish in Louisiana and currently serves the Cotton Valley formation, the Haynesville shale formation and the shallower producing sands in the Travis Peak formation. The Legacy System consists of approximately 658 miles of high- and low-pressure gathering lines and served approximately 100,000 dedicated acres with access to seven major downstream markets, three third-party processing plants and the Panola County processing plants. The Legacy system has ten 1,340 bhp compressors and two additional compressors comprising 725 bhp, for a total of 14,125 bhp of compression. The Legacy gathering system has an aggregate capacity of approximately 500 MMcf/d. Our Legacy system gathers high-Btu natural gas with an NGL content between 2.0 and 5.2 GPM.

Other Midstream Natural Gas Assets

We own and operate approximately six miles of 6-inch natural gas pipeline, which we refer to as our Bethany Lateral, and a natural gas treating facility, which we refer to as our Stateline Treating facility. Our Stateline Treating facility is adjacent to our Bethany Lateral and is located southeast of the town of Bethany in Caddo Parish, Louisiana. Our Stateline Treating facility has an aggregate capacity of approximately 30 MMcf/d and provides CO_2 removal services on behalf of Associated Energy Services, LP ("AES").

Logistics Segment

As of December 31, 2014, our logistics segment consisted of the following transloading assets: (i) our Wildcat facility located in Carbon County, Utah, where we currently operate one skid transloader and two ladder transloaders, (ii) our Big Horn facility located in Big Horn County, Wyoming, where we currently operate one skid transloader and one ladder transloader, and (iii) our East New Mexico facility located in Sandoval County, New Mexico, where we currently operate one skid transloader. Our transloaders are used to unload crude oil from tanker trucks and load crude oil into railcars and temporary storage tanks. Our Wildcat and Big Horn facilities provide transloading services for production originating from well-established crude oil producing basins, such as the Uinta, Powder River and Permian Basins, which we believe are currently underserved by our competitors. Our skid transloaders each have a transloading capacity of 475 Bbls/hr, and our ladder transloaders each have a transloading capacity of 210 Bbls/hr. Each of our skid transloaders was acquired from the manufacturer within the last two years and was custom made to our specifications in order to maximize the capacity and flexibility of our transloading operations. Our top-loading, heated skid transloaders handle multiple grades of crude oil, including heavy and waxy crudes, which we believe enables us to provide our customers with flexible, efficient and reliable transloading services in a variety of conditions. In general, our ladder transloaders are used when the skid transloader is operating at maximum capacity or in the event the skid transloader experiences downtime for repairs or maintenance. We do not own the site on which our transloading assets are located or where we conduct our transloading operations, and we have site access agreements and rail siding leases at each of our transloading facilities.

Wildcat Facility

At our Wildcat facility, crude oil is delivered to our site by third-party tanker trucks. Currently, AES contacts Wild West Equipment & Hauling, LLC, who currently provides the labor in connection with our transloading operations at our Wildcat facility, when they have crude oil that they wish to have transferred from truck to railcar. The crude oil is then transferred from the truck to a railcar or to a third-party tank leased by AES using either a skid transloader or a ladder transloader. On July 31, 2013, we entered into fee-based transloading services agreements with AES at our Wildcat facility that provides for a fixed fee per barrel for transloading services, subject to a minimum volume commitment of 7,600 Bbls/d with respect to our skid transloader and 1,260 Bbls/d with respect to each of our ladder transloaders.

Big Horn Facility

At our Big Horn facility, crude oil is delivered to our site by third-party tanker trucks at AES's request. We transfer crude oil from truck to railcar or to a third-party tank leased by AES using either a skid transloader or a ladder transloader. On July 31, 2013, we entered into fee-based transloading services agreements with AES at our Big Horn facility that provides for a fixed fee per barrel, subject to a minimum volume commitment of 7,600 Bbls/d with respect to our skid transloader and 1,260 Bbls/d with respect to our ladder transloader.

East New Mexico Facility

On July 30, 2014, we entered into a Contribution Agreement with NuDevco Midstream Development and our general partner for the purchase of the East New Mexico Transloading Facility, located in Sandoval County, New Mexico. The purchase closed on August 1, 2014. At our East New Mexico facility, crude oil is delivered to our site by third-party tanker trucks. AES requests we transfer crude oil from truck to railcar or to a third-party tank leased by AES using a skid transloader. On August 1, 2014, we entered into fee-based transloading services agreements with AES at our East New Mexico facility that provides for a fixed fee per barrel, subject to a minimum volume commitment of 5,000 Bbls per weekday with respect to our skid transloader.

Amendment to Transloading Service Agreements

On February 27, 2015, we entered into amendments to our (i) Wildcat facility transloading services agreement, (ii) Big Horn transloading services agreement and (iii) Ladder transloading services agreement, all of which are transloading services agreements with AES, an affiliated party. The amendments extend the terms, including the minimum volume commitments, associated with these transloading services agreements until February 27, 2020, or five years from the date of the amendment.

Our Fee-Based Commercial Agreements

Prior to July 31, 2013, we generated revenues primarily under keep-whole and other commodity-based gathering and processing agreements with third parties and their affiliates. On July 31, 2013, we terminated the existing commodity-based gas gathering and processing agreement with AES, assigned to AES all of the remaining keep-whole and other commodity-based gathering and processing agreements with third party customers and entered into a new three-year fee-based gathering and processing agreement with AES with a minimum volume commitment and annual inflation adjustments and new three-year fee-based transloading services agreements with AES at our Wildcat and Big Horn facilities.

Under our new gathering and processing agreement, AES pays us a fixed fee per Mcf (subject to an annual inflation adjustment) for gathering, treating, compression and processing services and a per gallon fixed fee for NGL transportation services. The agreement provides for a minimum volume commitment of 80 MMcf/d, which can be periodically increased. Under our transloading services agreements, AES pays us a fixed fee per barrel. The Wildcat and Big Horn agreements provide for a minimum volume commitment of 7,600 Bbls/d at each facility with respect to our skid transloaders and 1,260 Bbls/d with respect to each of our ladder transloaders. The East New Mexico agreement provides for a minimum volume commitment of 5,000 Bbls per weekday for the skid transloader at the facility.

The following table summarizes certain information regarding our fee-based commercial agreements with Anadarko and AES:

Agreement	Current Term Expiration	Renewal	Minimum Volume Commitment
Anadarko Panola County Agreement I	July 31, 2015	Year-to-year	Yes
Anadarko Panola County Agreement II	March 31, 2019	Month-to-month	Yes
AES Panola County Agreement (1)	Three years	Year-to-year	100 MMcf/d
Anadarko Tyler County Agreement	October 31, 2015	Year-to-year	No
AES Wildcat Skid Transloading Agreement (1)	Five years	Year-to-year	7,600 Bbls/d
AES Big Horn Skid Transloading Agreement (1)	Five years	Year-to-year	7,600 Bbls/d
AES Master Ladder Transloading Agreement (1)	Five years	Year-to-year	3,780 Bbls/d
AES East New Mexico Agreement (2)	Three years	Year-to-year	5,000 Bbls per weekday

(1) The AES agreements were entered into between us and AES in conjunction with the closing of the IPO on July 31, 2013. In connection with the Closing, the Transloading Agreements were extended until February 27, 2020, or five years from the date of the amendment. For additional information relating to our current sponsor relationship, please see Items 1 and 2 - "Business and Properties - Sponsor Relationship" included in this Form 10-K.

(2) The AES East New Mexico agreement was entered into between us and AES in conjunction with the dropdown from NuDevco on August 1, 2014. The initial term of this agreement is three years. AES is an affiliate under common control of NuDevco. For additional information relating to our current sponsor relationships, please see Items 1 and 2 - "Business and Properties - Sponsor Relationship" included in this Form 10-K.

As part of the Transactions, we also acquired certain contracts associated with the Legacy System. Major customers with long-term contracts on the Legacy System include BG, BP plc and Devon Energy Corporation, Endeavor Energy Resources, L.P., EXCO, Sabine Oil & Gas LLC and Samson Resources Corporation, among others. The Legacy System cash flows are primarily fee-based and the contracts have a remaining life varying from one year to life of lease.

STRATEGY

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

- Increase capacity utilization and throughput volumes on our existing systems. Our systems are designed to benefit from incremental volumes arising from high-density, infill drilling on existing pad sites already connected to our systems and do not require significant additional capital expenditures to handle such volumes. We intend to continue to focus on the stability of cash flows that we generate by optimizing returns from our existing asset portfolio and maximizing the utilization of our assets by increasing throughput volumes from existing customers and connecting new customers to our systems. We continually monitor field development activity by our customers, and we work closely with customers to tailor and enhance our service offerings to maximize the efficiency and economics of their production.

- Execute on organic growth and development opportunities. While our existing midstream and transloading assets provide us with significant organic growth opportunities, we also intend to execute organic growth and development opportunities associated with increases in natural gas, NGLs and crude oil production by increasing our midstream and transloading service offerings with existing customers and obtaining new customers. Further, we intend to expand our operations into new basins with underserved natural gas midstream and crude oil infrastructure where we can serve as a key strategic provider to strong customers under long-term commitments. We believe such opportunities exist in unconventional resource plays that are well positioned for accelerated production growth due to the inadequate level of existing natural gas transportation infrastructure in these plays relative to demand for such infrastructure as a result of increased drilling activity. We expect to accomplish these objectives by leveraging our current management team's expertise in successfully constructing, developing and optimizing midstream infrastructure assets. We also are actively pursuing projects to increase throughput or increase margins on our existing systems.

- Pursue accretive acquisitions from Azure and third parties. We intend to pursue acquisitions of additional midstream assets from Azure over time. We also intend to pursue accretive acquisitions of complementary assets from third parties.
- Acquisitions from Azure: We believe that Azure's economic interest in us incentivizes it to offer us acquisition opportunities, including additional interests in its existing midstream assets, although it is under no obligation to do so. We have a right of first offer to acquire the remaining midstream assets from Azure prior to that interest or assets being sold to a third party. We believe that Azure is strongly positioned to continue pursuing and developing integrated midstream projects, which may involve the development, construction and operation of pipelines, processing plants and associated infrastructure, which would allow customers to deliver crude oil and natural gas to transmission pipelines. Furthermore, we believe that the ability of Azure to pursue and develop integrated energy infrastructure projects will create potential acquisition opportunities for us in the future.
- Acquisitions from third parties: In the near term, we intend to pursue acquisition opportunities from third parties that we can finance on an accretive basis. Such acquisitions could be pursued independently by us or jointly with Azure.
- Diversify our assets through acquisitions of assets with exposure to other basins and hydrocarbons. While our current operations represent our core business, we intend to diversify our basin exposure into new, high-growth regions, as well as expand our operational capabilities into natural gas processing and crude oil services, primarily through acquisitions. We expect to continue to pursue opportunities to acquire crude oil, NGL and natural gas assets that (i) complement our existing business, (ii) allow us to integrate additional midstream services, (iii) balance our commodity profile and (iv) enhance our basin diversity. We anticipate that our highly qualified management team and energy- focused sponsor, Azure, will provide us with an advantage in pursuing these acquisitions as compared to other competitors. We and our sponsor, Azure, are frequently involved in discussions with third parties regarding the purchase of natural gas and crude oil midstream energy infrastructure assets. We intend to continue to evaluate opportunities to acquire or develop other midstream energy infrastructure assets that complement our existing business and allow us to leverage our management team's development and industry expertise throughout the midstream value chain.
- Generate stable and predictable fee-based cash flows. We intend to continue pursuing accretive opportunities to provide fixed-fee and fixed-spread services to existing and new customers, limiting our direct exposure to commodity price volatility when possible. We plan to focus on obtaining additional long-term commitments from customers, which may include minimum volume and revenue commitments, acreage dedications or life of lease arrangements. The long-term, fixed-fee and and fixed-spread nature of our contracts reduces direct commodity exposure and provides relatively predictable revenue streams.

COMPETITIVE STRENGTHS

We believe that we are well positioned to execute our primary business strategies because of the following competitive strengths:

- Strategically Located Assets. Our midstream energy infrastructure assets are strategically positioned within core areas of the Haynesville shale. The formations in the basins served by our assets have been accessed by experienced producers who have been able to achieve a high level of EURs on the wells completed. We believe that producers will continue their drilling and completion activities in our areas of operation in a variety of commodity price environments because the return economics associated with core-area wells remain favorable in lower pricing environments compared to less economic areas of production. We believe our core producers can earn acceptable rates of return above their cost of capital when natural gas prices are at low cycle levels. Additionally, continued drilling activity in these formations positions us to pursue attractive growth opportunities by further developing and optimizing our systems and by developing or acquiring complementary systems within our geographic areas of operation.
- Modern and Efficient Assets. All of our gathering systems, processing plants and transloaders were recently constructed and operate with flexibility and efficiency, allowing us to tailor our commercial agreements to meet

specific customer needs, which we believe provides us with a competitive advantage. We also believe our highly efficient, modern infrastructure provides us the ability to deliver throughput volumes with a lower amount of compression while reducing gas losses and to add additional throughput volumes with marginal incremental costs and capital expenditures.

- Relationship with Azure. We believe that our relationship with Azure will provide us with opportunities to acquire additional midstream natural gas assets that it owns and develops, as well as opportunities to minimize our direct commodity price exposure with fee-based contracts supporting the assets it may offer to us. Azure is fully incentivized to grow our distributions through capitalizing on synergies and potential drop downs into the Partnership over time. Additionally, Azure's sponsors, Energy Spectrum and Tenaska Capital Management, may be able to facilitate access to substantial investment capital and a broad portfolio of midstream energy assets to facilitate new business opportunities.
- Relatively Stable and Predictable Cash Flows. Our cash flows are largely protected from commodity price fluctuations due to our strategy of fee-based commercial agreements, the substantial majority of which have minimum volume commitments and annual inflation adjustments. We generate the majority of our revenues under long-term, fixed-fee and fixed-spread natural gas gathering, processing and natural gas sales agreements that are intended to mitigate our direct commodity price exposure and enhance the stability of our cash flows. We also have gas gathering and processing and transloading service agreements under contracts with minimum volume commitments.
- Strong Customer Relationships. We have a strong customer base consisting of large and small independent producers, large pipeline companies and marketers, and we believe that we have established a reputation as a responsive and reliable operator by providing high quality services and tailoring solutions to meet the needs of our customers. We also believe the services we provide are critical to enhancing natural gas production and that we are able to provide the most economic transportation solution for our customers. As a result, our high-quality service results in recurring revenues and strong customer relationships, further supporting the stability of our cash flows. These relationships in turn result in organic growth opportunities as our customers expand their drilling operations or their field development creates the need for additional midstream services. We believe that our advantaged position in leading producing regions, our highly efficient operations and the long-term nature of our customer relationships enhance our ability to generate stable and growing cash flows.
- Entrepreneurial and Experienced Energy Industry Management Team. Our executive management team, including the newly appointed executives, have over 130 years of combined midstream experience and have demonstrated a successful track record of growing businesses and of identifying and developing midstream energy opportunities. Members of our newly appointed management team were the key developers of the Laser Northeast Gathering System in the Marcellus that was sold to Williams Partners, L.P. in 2012 and have been instrumental in developing other critical midstream assets across multiple basins. Further, our President, Chief Financial Officer and Vice President of Engineering and Pipeline Services have prior experience serving as senior officers of publicly traded limited partnerships, which affords us a competitive advantage versus many of our peers that have less or no experience managing public companies. We employ engineering, construction and operations teams that have significant experience in designing, constructing and operating large midstream energy projects and have demonstrated a continued focus on improving operational efficiency of our acquired assets.

We believe that we effectively leverage our competitive strengths to successfully implement our strategy; however, our business involves numerous risks and uncertainties that may prevent us from achieving our primary business objective. For additional information relating to the risks associated with our business, please see Item 1A , "Risk Factors" included in this Annual Report on Form 10-K.

SPONSOR RELATIONSHIP

As of December 31, 2014, NuDevco Midstream, our original sponsor, and affiliates held 10,663,810 of our limited partner units, representing 60.2% of the outstanding limited partner interest, and, through its ownership of our general partner, indirectly held 357,935 general partner units representing a 2.0% economic general partner interest in us and 100% of our incentive distribution rights ("IDRs"). As of December 31, 2014, the public held 7,039,983 common units, representing 39.8% of the outstanding limited partner interest in us.

Subsequent to the closing of the Transactions on February 27, 2015, Azure owns 100% of our general partner and indirectly holds all 357,935 general partner units representing a 2% general partner interest in us and 90 IDR Units, representing 90% of our IDR Units. Additionally, Azure purchased an option to acquire up to 20% of each of our common and subordinated units held by NuDevco as of the execution date of the Transaction Agreement. In connection with the closing of the Transactions, we terminated our existing Omnibus Agreement dated July 31, 2013 among us, NuDevco Partners, NuDevco Partners Holdings, LLC, a Texas limited liability company (“Holdings”), NuDevco, the general partner and we entered into an omnibus agreement (the “New Omnibus Agreement”) with the general partner and Azure. The New Omnibus Agreement, among other things, states that:

- Azure will provide corporate, general and administrative services (the “Services”) on behalf of the general partner for the benefit of us and our subsidiaries;

- We are obligated to reimburse Azure and its affiliates for costs and expenses incurred by Azure and its affiliates in providing the Services on our behalf, including, but not limited to, administrative costs and the compensation costs of the employees of Azure and its affiliates that provide Services to us;

- The general partner or Azure may at any time temporarily or permanently exclude any particular Service from the scope of the New Omnibus Agreement upon 90 days’ notice;

- We or Azure may terminate the New Omnibus Agreement in the event that Azure ceases to control our general partner. Azure may also terminate the New Omnibus Agreement if our general partner is removed without cause and the units held by our general partner were not voted in favor of the removal; and

- We will have a right of first offer on any proposed transfer of any assets owned by Azure or its subsidiaries as of January 14, 2015.

INDUSTRY OVERVIEW

General

The midstream energy industry is the link between the exploration and production of natural gas and crude oil and the delivery of their components to industrial, commercial and residential end-user markets. The midstream industry is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas and crude oil producing wells.

The following diagram illustrates the various components of the natural gas and crude oil value chain and the extent of our current operations:

Midstream Natural Gas Services

The principal components of the midstream natural gas business consist of gathering, compressing, treating, dehydrating, processing, fractionating, transporting and marketing natural gas and natural gas liquids, or NGLs. Companies within this industry provide services at various stages along the natural gas value chain by gathering raw natural gas from producers at the wellhead, separating the hydrocarbons into dry gas (primarily methane) and NGLs, and then routing the separated dry gas and NGL streams to the next intermediate stage of the value chain or to transmission pipelines for delivery to end-user markets.

The range of services utilized by midstream natural gas service providers are generally divided into the following eight categories.

Gathering

At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads in the production area. These gathering systems transport natural gas from the wellhead to a central location for treating and processing. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow for additional production and well connections without significant incremental capital expenditures.

Compression

Gathering systems are operated at design pressures that enable the maximum amount of production to be gathered from connected wells. Through a mechanical process known as compression, volumes of natural gas at a given pressure are compressed to a sufficiently higher pressure, thereby allowing those volumes to be delivered into a higher pressure downstream pipeline to be brought to market. Since wells produce at progressively lower field pressures as they age, it becomes necessary to add additional compression over time near the wellhead to maintain throughput across the gathering system.

Treating and Dehydration
Treating and dehydration involves the removal of impurities such as water, carbon dioxide, nitrogen and hydrogen sulfide that may be present when natural gas is produced at the wellhead. During this process, the natural gas is dehydrated to remove the saturated water and is chemically treated to separate the impurities from the gas stream. These impurities must be removed for the natural gas to meet the specifications for transportation on long-haul intrastate and interstate pipelines. Moreover, end users will not purchase natural gas with a high level of these impurities.
Processing
Processing involves the removal of the heavier hydrocarbon components from the gas stream. Even after treating and dehydration, natural gas may not be suitable for long-haul intrastate and interstate pipeline transportation or commercial use because it contains heavier NGLs components, as well as natural gas condensate. The removal and separation of NGLs usually takes place in a processing plant using industrial processes that exploit differences in the weights, boiling points, vapor pressures and other physical characteristics of NGL components. Although heavier NGLs components can interfere with pipeline transportation, they are also valuable commodities once removed from the natural gas stream. Depending on the nature of processing contracts, the processor or the customer may take more or less commodity risk associated with the NGLs resulting from processing.
NGL Products Transportation
Once the NGL stream has been separated from the natural gas stream, and separated into products through fractionation, the resulting NGL products are then transported to downstream NGL networks or directly to end users.
Fractionation
Fractionation is the process by which the mixture of NGLs resulting from natural gas processing is separated into the NGL components prior to their sale to various petrochemical and industrial end users. Fractionation is accomplished by controlling the temperature of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate hydrocarbon products.
Natural Gas Transmission
Once the raw natural gas has been treated and processed, the remaining natural gas, or residue natural gas, is transported to end users. The transmission of natural gas involves the movement of pipeline-quality natural gas from gathering systems and processing facilities to wholesalers and end users, including industrial plants and local distribution companies, or LDCs. LDCs and marketers, if the LDC is open to competition, purchase the natural gas and market it to commercial, industrial and residential end users. Transmission pipelines generally span considerable distances and consist of large-diameter pipelines that operate at higher pressures than gathering pipelines to facilitate the transportation of greater quantities of natural gas. The concentration of natural gas production in a few regions of the United States generally requires transmission pipelines to cross state borders to meet national demand. These pipelines are referred to as interstate pipelines and primarily are regulated by federal agencies or commissions, including the FERC. Pipelines that transport natural gas produced and consumed wholly within one state are generally referred to as intrastate pipelines. Intrastate pipelines are primarily regulated by state agencies or commissions.
Marketing
Marketing consists of the purchase and then sale of natural gas and NGLs to end-use customers. Marketing, and related commodity risk, can involve some or all of the intermediate steps that particular purchases and sales require, including arranging transportation, storage and any other steps required to facilitate the transaction.
Typical Contractual Arrangements
Midstream natural gas services, other than transportation, are usually provided under contractual arrangements that vary in the amount of commodity price risk they carry. Three typical contract types are described below:

- Fee-based. Under fee-based arrangements, the service provider typically receives a fee for each unit of natural gas gathered, treated and/or processed at its facilities. As a result, the price per unit received by the service provider does not vary with commodity price changes, minimizing the service provider's direct commodity price risk exposure.
- Percent-of-proceeds, percent-of-value or percent-of-liquids. Percent-of-proceeds, percent-of-value or percent-of-liquids arrangements may be used for gathering and processing services. Under these arrangements, the service provider typically remits to the producers either a percentage of the proceeds from the sale of residue and/or

NGLs or a percentage of the actual residue and/or NGLs at the tailgate. These types of arrangements expose the processor to

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commodity price risk, as the revenues from the contracts directly correlate with the fluctuating price of natural gas and/or NGLs.

- Keep-whole. Keep-whole arrangements may be used for processing services. Under these arrangements, the service provider keeps 100% of the NGLs produced, and the processed natural gas, or value of the gas, is returned to the producer. Since some of the gas is used and removed during processing, the processor compensates the producer for the amount of gas used and removed in processing by supplying additional gas or by paying an agreed-upon value for the gas utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs.

There are two forms of contracts utilized in the transportation of natural gas, NGLs and crude oil, as described below:

- Firm. Firm transportation service requires the reservation of pipeline capacity by a customer between certain receipt and delivery points. Firm customers generally pay a demand or capacity reservation fee based on the amount of capacity being reserved, regardless of whether the capacity is used, plus a usage fee based on the amount of natural gas transported.
- Interruptible. Interruptible transportation service is typically short-term in nature and is generally used by customers that either do not need firm service or have been unable to contract for firm service. These customers pay only for the volume of gas actually transported. The obligation to provide this service is limited to available capacity not otherwise used by firm customers, and, as such, customers receiving services under interruptible contracts are not assured capacity on the pipeline.

Both firm and interruptible service contracts may contain dedication provisions. Dedication provisions effectively dedicate any and all production from specified leases or existing and future wells on dedicated lands for a specified term. Dedication provision may alternatively continue in effect for as long there is commercial production from the identified wells or leases, which are often referred to as “life-of-reserves” or “life-of-lease” dedications. Dedication provisions typically remain in effect even if ownership of the subject acreage or well changes in the future.

For additional information relating to our contractual arrangements, please see Items 1 and 2 “Business and Properties-Our Assets and Areas of Operation-Our Fee-Based Commercial Agreements” included in this Annual Report on Form 10-K.

Crude Oil Transportation & Logistics

Crude oil gathering assets provide the link between crude oil production gathered at the well site or nearby collection points and crude oil terminals and storage facilities, long-haul crude oil pipelines, railcars and refineries. Crude oil gathering assets generally consist of a network of smaller-diameter pipelines that are connected directly to the well site or central receipt points delivering into larger-diameter trunk lines. Trucking operations and railcars are often used to supplement pipeline systems by gathering and transporting crude oil production from remote well sites that are not directly connected to pipeline gathering infrastructure. Competition in the crude oil gathering industry is typically regional and based on proximity to crude oil producers, as well as access to viable delivery points. Overall demand for gathering services in a particular area is generally driven by crude oil producer activity in the area.

Crude oil rail terminals, or transloaders, are an integral part of ensuring the movement of new crude oil production from the developing shale plays, as well as crude oil production from conventional basins, in the United States and Canada. In general, transloaders used to load railcars and transport the commodity out of developing basins into markets where transloaders are used to unload railcars and store crude oil volumes for third parties until the oil is redelivered to markets via pipelines, trucks or rail to delivery points.

CUSTOMERS

The primary suppliers of natural gas to us are a broad cross-section of the natural gas producing community. These suppliers include small and large exploration and production companies, large pipeline companies and natural gas marketers. Among those customers currently supplying natural gas to us for treating and processing are Anadarko, Kinder Morgan, Energy Transfer and AES. Customers on our Legacy System include BG Group, plc, BP plc, Devon

Energy Corporation, Endeavor Energy Resources, L.P., EXCO Resources, Inc., Sabine Oil & Gas LLC and Samson Resources Corporation, among others. We actively seek new natural gas producing customers for all of our facilities to increase throughput volume and to offset natural declines in the production from connected wells. We obtain new natural gas supplies in our operating areas by contracting for

production from new wells, by connecting new wells drilled on dedicated acreage and by obtaining natural gas that has been directly received or released from other gathering systems.
For the year ended December 31, 2014, Anadarko and AES each accounted for more than 10% of our revenues. Although we have gathering, processing or transportation agreements with these customers, these agreements have remaining terms ranging from one to five years. As these agreements expire, we will have to renegotiate extensions or renewals with these customers or replace the existing contracts with new arrangements with other customers. If either of these customers were to default on its contracts or if we were unable to renew our contracts with them on favorable terms, we may not be able to replace such customers in a timely manner, on favorable terms or at all. In any of these situations, our revenues and cash flows and our ability to make cash distributions to our unitholders would be materially and adversely affected.
In addition, AES is our sole customer with respect to our crude oil logistics business, and we expect to continue to derive the substantial majority of our transloading revenues from AES. AES is contracted for 100% of the capacity at our Wildcat, Big Horn, and East New Mexico facilities. Such concentration subjects us to increased risk in the case of nonpayment, nonperformance or non-renewal by AES under the transloading services agreements that we entered into with AES at the closing of our IPO, three of which were subsequently extended in connection with the Transactions until February 27, 2020. Any adverse developments concerning AES could materially and adversely affect our crude oil logistics business.

COMPETITION

The natural gas gathering, transmission, treating and processing businesses are highly competitive, and we face strong competition in acquiring new natural gas supplies. Our competition in obtaining additional natural gas supplies include interstate and intrastate pipelines and other midstream companies that gather, treat, process and market natural gas in the vicinity of our facilities. The ability to secure the dedication of natural gas supplies is primarily based on the reputation, efficiency, flexibility and reliability of the processor and the pricing of services. When commodity prices are high, producers generally desire to retain the full benefits of such increased commodity prices. Accordingly, in a high NGL pricing environment, fee-based arrangements are preferred by most producers. Our ability to tailor processing agreements to meet the specific needs of our customers, our ability to offer lower-priced services due to our relatively lower capital investments as compared to the rest of the industry and higher recovery efficiencies and lower fuel consumption at our facilities factor positively in our ability to compete in the markets we serve. The primary competitors of our Panola plants are DCP Midstream and MarkWest. The primary competitors of our Tyler County processing facility are Eagle Rock Energy Partners, L.P. and Enterprise.
The crude oil logistics business, including the crude oil transloading business, is highly competitive. Our competition in obtaining new customers for our transloading services include Crosstex Energy, L.P., Rose Rock Midstream, LP and private logistics companies transloading crude oil in the areas in which we operate. The ability to secure additional agreements for transloading services is primarily based on the reputation, efficiency, flexibility, location and reliability of the service provided and the pricing of services. Since we generally target niche areas that are in need of crude oil logistics services, competition is less than if we were to try to compete in more active crude oil plays such as the Bakken, Utica and Marcellus shale plays. Our only current customer for our crude oil transloading services is AES.

SAFETY AND MAINTENANCE

Our natural gas and NGL transportation pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the Department of Transportation (“DOT”) under the Natural Gas Pipeline Safety Act of 1968, as amended (“NGPSA”), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (“HLPSA”), with respect to NGLs and condensates. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas and NGL pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, design pressures, maximum operating pressures, pipeline patrols and leak surveys, minimum depth requirements, and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Where applicable, the NGPSA and HLPSA require any entity that owns or operates pipeline facilities to comply with the regulations under these acts, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that our pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

Our pipelines are also subject to regulation by PHMSA under the Accountable Pipeline Safety and Partnership Act of 1996 (“ASPA”), the Pipeline Safety Improvement Act of 2002, as amended by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (“PIPES Act”), and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 (the “2011 Pipeline Safety Act”). PHMSA has established a series of rules, which require pipeline operators to develop and implement integrity management programs for certain gas pipelines that, in the event of a failure, could affect “high consequence areas”, including high population areas that are sources of drinking water and unusually sensitive ecological areas. Similar rules are also in place for operators of certain hazardous liquid pipelines including lines transporting NGLs and condensates.

The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines and operator verification of records confirming the maximum allowable pressure of certain gas transmission pipelines. In September 2013, PHMSA published a final rulemaking consistent with the 2011 Pipeline Safety Act that increases the maximum administrative civil penalties for violation of the pipeline safety laws and regulations to $200,000 per violation per day, with a maximum of $2,000,000 for a related series of violations.

PHMSA has also published advanced notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to extend the integrity management requirements to additional types of facilities, such as gathering pipelines and related facilities.

Most recently, in an August 2014 report to Congress from the U.S. Government Accountability Office (“GAO”), the GAO acknowledged PHMSA’s continued assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply. The adoption of these and other laws, regulations, and policies that apply more comprehensive or stringent safety standards to gathering lines could require us to install new or modified safety controls, pursue added capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs and compliance expenditures that could be significant and have a material adverse effect on our financial position or results of operations and ability to make distributions to our unitholders. Legislative and regulatory changes may also result in higher penalties for the violation of Federal pipeline safety regulations.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. Texas has developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. We currently estimate an annual average cost of $0.1 million for 2015 to perform necessary integrity management program testing on our pipelines required by existing PHMSA and state regulations. This estimate does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. However, we do not expect that any such costs would be material to our financial condition or results of operations. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered and adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

We and the entities in which we own an interest are also subject to:

- the U.S. Environmental Protection Agency (“EPA”) Chemical Accident Prevention provisions, also known as the Risk Management Plan requirements, which are designed to prevent the accidental release of toxic, reactive, flammable or explosive materials;
- the U.S. Occupational Safety and Health Administration Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive materials; and
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the Department of Homeland Security Chemical Facility Anti-Terrorism standards, which are designed to regulate the security of high-risk chemical facilities.

We believe that all of our facilities have been constructed and are operated and maintained in substantial compliance with applicable federal, state, and local pipeline safety-related laws and regulations. We expect that any legislative or regulatory changes would allow us time to become compliant with new requirements, however, costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of any new laws or rules or the future costs of compliance associated with such requirements.

REGULATION OF OPERATIONS

Regulation of natural gas gathering and sales and transportation of NGLs may affect certain aspects of our business and the market for our products and services.

Regulation of Natural Gas Gathering

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of Federal Energy Regulatory Commission ("FERC"). We believe that our natural gas pipelines meet the traditional tests that FERC has used to determine that a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress.

State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, complaint-based rate regulation and, nondiscriminatory take requirements. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels.

Our gathering and processing operations are subject to ratable take and common purchaser statutes in Texas. The Texas ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, Texas common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to process or gather natural gas. Texas has adopted a complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. We cannot predict whether such a complaint will be filed against us in the future.

NGL Pipeline Regulation

Our NGL pipelines are regulated as a utility by the Texas Railroad Commission ("TRRC"). The TRRC’s jurisdiction extends to both rates and pipeline safety. The rates we charge for NGL transportation services are deemed just and reasonable under Texas law unless challenged in a complaint. Should a complaint be filed or should regulation become more active, our business may be adversely affected. The TRRC requires that intrastate NGL pipelines file tariff publications that contain all the rules and regulations governing the rates and charges for service performed. The applicable Texas statutes require that NGL pipeline rates provide no more than a fair return on the aggregate value of the pipeline property used to render services. State commissions have generally not been aggressive in regulating common carrier pipelines and have generally not investigated the rates or practices of NGL pipelines in the absence of shipper complaints. Complaints to state agencies have been infrequent and are usually resolved informally. Although we cannot assure that our intrastate rates would ultimately be upheld if challenged, we believe that, given this history, the tariffs now in effect are not likely to be challenged or, if challenged, are not likely to be ordered to be reduced.

Natural Gas Processing

Our natural gas processing operations are not presently subject to FERC regulation. However, starting in May 2009 we were required to report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year.

Availability, Terms and Cost of Pipeline Transportation

Our processing facilities and NGL transportation services are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and, if a complaint is filed, state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to our processing operations and our natural gas and NGL transportation services. We do not believe that we would be affected by any such FERC action materially differently than other natural gas processors and natural gas and NGL marketers with whom we compete.

Sales of NGLs

The price at which we buy and sell NGLs is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the NGA, the NGPA, and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

Anti-Market Manipulation and Market Transparency Rules

We are subject to the anti-market manipulation provision in the NGA, as amended by the Energy Policy Act of 2005, or EP Act 2005, which makes it unlawful for any entity to engage in prohibited behavior in contravention of FERC rules and regulations. EP Act 2005 authorizes FERC to impose fines of up to one million dollars ($1,000,000) per day per violation of the NGA, the NGPA or their implementing regulations. In addition, the CFTC is directed under the Commodities Exchange Act, or CEA to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Act and other authority, CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. CFTC also has statutory authority to seek civil penalties of up to the greater of one million dollars ($1,000,000) or triple the monetary gain to the violator for violations of the anti-market manipulation sections of CEA.

We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation, including a requirement that wholesale buyers and sellers of annual quantities of 2.2 million MMBtu or more of natural gas in a calendar year report aggregate volumes of natural gas purchased or sold at wholesale to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other similarly situated midstream companies with whom we compete.

Other State and Local Regulation of Operations

Our business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters.

ENVIRONMENTAL MATTERS

Our operation of pipelines, plants and other facilities for the gathering, compressing, treating and transporting of natural gas and other products, and the operation of our crude oil transloading facilities, is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. These laws and regulations may 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;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- requiring the acquisition of permits to conduct regulated activities and delaying system modification or upgrades until permit applications are approved;
- 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 issued pursuant to 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, the imposition of investigatory, remedial and

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corrective action obligations and the issuance of orders enjoining some or all of our operations in affected areas. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances, petroleum hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, petroleum hydrocarbons or other waste products into the environment.

We have implemented programs and policies designed to keep our pipelines, plants and other facilities in compliance with existing environmental laws and regulations. Nonetheless, Congress and the federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, transportation, disposal, pollution control or cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs. The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and 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. Moreover, accidental releases or spills may occur in the course of our operations, and we may incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. We may not be able to recover all or any of these costs from insurance.

We believe that we are in substantial compliance with applicable environmental laws and regulations, and do not believe that compliance with such laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. In addition, we believe that the various environmental activities in which we are presently engaged are not expected to materially interrupt or diminish our operational ability to gather, compress, treat and transport natural gas. We cannot assure you, however, that future events, such as changes in existing laws, regulations or enforcement policies, the promulgation of new laws or regulations or the interpretation of existing enforcement policies will not cause us to incur significant costs. Below is a discussion of the more material environmental laws and regulations, as amended from time to time, that relate to our business.

Hazardous Substances and Wastes

Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, non-hazardous and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of such wastes or hydrocarbons. For instance, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third-parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. In the course of our ordinary operations, we handle hazardous substances within the meaning of CERCLA, or similar state statutes and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. While RCRA regulates both non-hazardous and hazardous wastes, it imposes more stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. We generate minimal amounts of hazardous wastes; however, it is possible that the wastes currently generated by us and characterized as non-hazardous wastes could undergo regulatory change in the future and be designated as "hazardous wastes," which could subject us to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

We currently own or lease properties where petroleum hydrocarbons are being or have been handled for many years. Although we and previous operators have utilized operating and disposal practices that were standard in the industry at the time, hazardous substances, petroleum 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 perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Air Emissions

Our operations are subject to the federal Clean Air Act ("CAA") and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, processing plants and transloading and storage facilities, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce 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. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions under either or both federal or state law. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015, which proposes to revise the National Ambient Air Quality Standard for ozone between 65 to 70 parts per billion (“ppb”) for both the 8-hour primary and secondary standards. The current primary and secondary ozone standards are set at 75 ppb. EPA also requested public comments on whether the standard should be set as low as 60 ppb or whether the existing 75 ppb standard should be retained. If EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could apply to our operations. Compliance with this or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business as well as the business of similarly situated companies in the industry.

Water Discharges and Oil Releases

The Federal Water Pollution Control Act, also known as 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. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure plan requirements imposed under the Clean Water Act require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon 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. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for noncompliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations

The Oil Pollution Act of 1990 ("OPA"), which amends the Clean Water Act, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. OPA and its implementing regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A “responsible party” under OPA includes owners and operators of onshore facilities and pipelines. Under OPA, owners and operators of facilities that handle, store, or transport oil are required to develop and implement oil spill response plans, and establish and maintain evidence of financial responsibility sufficient to cover liabilities related to an oil spill for which such parties could be statutorily responsible.

Hydraulic Fracturing

Some of our customers’ oil and gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. The process is typically regulated by state oil and gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of

Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management ("BLM") issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. At the state level, a growing number of states, including Texas, where we conduct operations and our customers conduct hydraulic fracturing, have adopted and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality and the EPA. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. While we do not conduct hydraulic fracturing, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers' operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our gathering, transportation and processing services, which could in turn adversely affect our revenues and results of operations.

Endangered Species

The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the federal Migratory Bird Treaty Act. While some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our midstream services.

Climate Change

Based on its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes, The EPA has adopted regulations under the Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by the states. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission and storage facilities. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual GHG emissions reporting is currently required to include GHG emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. We are monitoring GHG emissions from certain of our operations in accordance with current GHG emissions reporting requirements pursuant to the applicable reporting obligations and are currently assessing the potential impact that the December 9, 2014 proposed rule may have on our future reporting obligations, should the proposal be adopted.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our or our oil and natural gas production customers' equipment and operations could require us or our customers to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs we gather and process or crude oil that we transport. For example, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration’s efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025 Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate change that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have exploration and an adverse effect on our operations.

Anti-terrorism Measures

The Department of Homeland Security Appropriation Act of 2007 requires the Department of Homeland Security, or DHS, to issue regulations establishing risk-based performance standards for the security of chemical and industrial facilities, including oil and gas facilities that are deemed to present “high levels of security risk.” DHS issued an interim final rule in April 2007 regarding risk-based performance standards to be attained pursuant to this act and, subsequently issued an Appendix A to the interim rules that establish chemicals of interest and their respective threshold quantities that will trigger compliance with these interim rules. Covered facilities that are determined by DHS to pose a high level of security risk will be required to prepare and submit Security Vulnerability Assessments and Site Security Plans as well as comply with other regulatory requirements, including those regarding inspections, audits, recordkeeping, and protection of chemical-terrorism vulnerability information.

We may also be subject to future anti-terrorism and/or cyber-security requirements of DHS or other governmental agencies. DHS has issued its National Infrastructure Protection Plan calling for broadened efforts to “reduce vulnerability, deter threats, and minimize the consequences of attacks and other incidents” as they relate to pipelines, processing facilities and other infrastructure. The precise parameters of future regulations and any related sector-specific requirements are not currently known, and there can be no guarantee that any final rules that might be applicable to our facilities will not impose costs and administrative burdens on our operations.

EMPLOYEES

As of December 31, 2014, our general partner and its affiliates had approximately 63 employees performing services for our operations. None of these employees are covered by collective bargaining agreements, and we believe that our general partner and its affiliates have a satisfactory relationship with those employees.

In connection with the Transaction, we entered into the New Omnibus Agreement. Under the New Omnibus Agreement, Azure provides corporate, general and administrative services (the “Services”) on behalf of the general partner for our benefit. We are obligated to reimburse Azure and its affiliates for costs and expenses incurred by Azure and its affiliates in providing the Services to us, including, but not limited to, administrative costs and the compensation costs of the employees of Azure and its affiliates that provide Services to us.

We are managed and operated by the board of directors and executive officers of our general partner. Neither we nor our subsidiaries have any employees. Our general partner has the sole responsibility for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our general partner.

Item 1A. Risk Factors
RISK FACTORS
Risks Related to our Business
We depend on a relatively small number of customers for a significant portion of our gross margin. The loss of any one or more of these customers could materially and adversely affect our ability to make distributions to our unitholders.
A significant portion of our gross margin is attributable to a relatively small number of customers. Anadarko and AES accounted for a substantial majority of our gross margin for the three months and year ended December 31, 2014. Although we have gathering and processing agreements with both of these customers, these agreements have remaining terms ranging from two to five years. As these contracts expire, we will have to renegotiate extensions or renewals with these customers or replace the existing contracts with new arrangements with other customers. If either of these customers were to default on its contract or if we were unable to renew our contract with either of these customers on favorable terms, we may not be able to replace such customers in a timely fashion, on favorable terms or at all. In any of these situations, our gross margin and cash flows and our ability to make cash distributions to our unitholders would be materially and adversely affected. We expect our exposure to concentrated risk of non-payment, non-performance or nonrenewal to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our gross margin.
In addition, AES is our sole customer with respect to our crude oil logistics business, and we expect to continue to derive the substantial majority of our transloading revenues from AES. Such concentration subjects us to increased risk in the case of nonpayment, nonperformance or nonrenewal by AES under the transloading services agreements. Any adverse developments concerning AES could materially and adversely affect our crude oil logistics business and could materially and adversely affect our ability to make distributions to our unitholders.
Subsequent to the Transactions, Anadarko and AES will continue to be significant to us. Additionally, the Legacy System has a natural gas sales agreement with Conoco Philips Company that is expected to account for approximately 10% of the gross margin of our combined businesses, including the Legacy System, based on pro forma unaudited financial results for the year ended December 31, 2014
We may not generate sufficient distributable cash flow to support the payment of the minimum quarterly distribution to holders of our common and subordinated units.
In order to support the payment of the minimum quarterly distribution of $0.35 per unit per quarter, or $1.40 per unit on an annualized basis, we must generate distributable cash flow of approximately $6.3 million per quarter, or $25.2 million per year, based on the number of common and subordinated units and the general partner interest outstanding as of December 31, 2014. We may not generate sufficient distributable cash flow each quarter to support the payment of the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- our ability to contract successfully for throughput volumes of natural gas and crude oil;
- the volume of natural gas we gather and process and the volume of NGLs we transport;
- the volume of crude oil that we transload;
- the level of production of crude oil and natural gas and the resultant market prices of crude oil, natural gas and NGLs;
- the level of competition from other midstream natural gas companies and crude oil logistics companies in our geographic markets;
- the level of our operating expenses;
- regulatory action affecting the supply of, or demand for, crude oil or natural gas, the transportation rates we can charge on our pipelines, how we contract for services, our existing contracts, our operating costs or our operating flexibility;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation;
- capacity charges and volumetric fees that we pay for NGL fractionation services;
- realized pricing impacts on our revenues and expenses that are directly subject to commodity price exposure;

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- damage to pipelines, facilities, plants, related equipment and surrounding properties caused by hurricanes, earthquakes, floods, fires, severe weather, casualty losses, explosions and other natural disasters and acts of terrorism including damage to third party pipelines or facilities upon which we rely for transportation services;
- outages at the processing or fractionation facilities owned by us or third parties caused by mechanical failure and maintenance, construction and other similar activities;
- actions taken by third-party operators, processors, and transporters; and
- leaks or accidental releases of products or other materials into the environment, whether as a result of human error or otherwise.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level and timing of our expansion capital expenditures and our maintenance capital expenditures;
- the cost of acquisitions, if any;
- the level of our general and administrative expenses, including reimbursements to our general partner and its affiliates for services provided to us;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

Our commercial agreements subject us to renewal risks.

We currently gather, process and transport most of the natural gas, and purchase, transport and sell NGLs, on our midstream natural gas systems under commercial agreements with terms of various durations. In addition, we provide gathering, processing, NGL transport and transloading services to AES under agreements with five-year terms. As our commercial agreements expire, we will have to negotiate extensions or renewals with our customers, including AES and Anadarko, or enter into new agreements with customers. We may be unable to renew, or enter into new, agreements on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular agreement with an existing customer or the overall mix of our contract portfolio.

If the economic benefit to AES or Anadarko of their minimum volume commitments at our Panola County processing facilities is less than they have projected, whether because the volumes of natural gas actually delivered by them are below the committed amount or otherwise, they may be unwilling to negotiate extensions or renewals of their commercial agreements with us on terms acceptable to us. For example, we expect that there could be volatility in the volumes of natural gas delivered by AES and Anadarko to our Panola County processing facilities, and at times the volumes delivered by AES and Anadarko could be below their minimum volume commitments. As a result, AES and Anadarko may make shortfall payments to us from time to time with respect to their minimum volume commitments. Similarly, if the economic benefit to AES of its minimum volume commitment at our Wildcat and Big Horn facilities is less than AES has projected, whether because the volumes of crude oil actually delivered by AES are below the committed amount or otherwise, AES may be unwilling to negotiate extensions or renewals of its transloading services agreements with us on terms acceptable to us. For example, we expect there could be volatility in the volumes of crude oil delivered by AES for transloading at our Wildcat and Big Horn facilities, and at times the volumes delivered by AES could be below the aggregate minimum volume commitment under the transloading services agreements that we entered into with AES at the closing of the IPO.

To the extent we are unable to renew our existing contracts or enter into new contracts on terms that are favorable to us or to successfully manage our overall contract mix over time, our revenues, gross margin and cash flows could decline and our ability to make distributions to our unitholders could be materially and adversely affected.

Our industry is highly competitive, and increased competitive pressure could materially and adversely affect our business and results of operations.

We compete with other midstream natural gas and crude oil logistics companies in our areas of operation. Some of our competitors are large companies that have greater financial, managerial and other resources than we do. Our competitors may expand or construct gathering, compression, treating, processing or transportation systems or transloading facilities that would

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create additional competition for the services we provide to our customers. In addition, our customers may develop their own gathering, compression, treating, processing or transportation systems or transloading facilities in lieu of using ours. While we seek to provide transloading services in markets that we believe are currently under-served by our competitors, the barriers to entry in such markets are low, which may induce more of our competitors to attempt to provide similar transloading services in such markets. All of these competitive factors could materially and adversely affect our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Because of the natural decline in production from existing wells in our areas of operation, our success depends in part on our customers replacing declining production and also on our ability to obtain new sources of natural gas and crude oil, which is dependent on factors beyond our control. Any decrease in the volumes of natural gas that we gather, process or transport, or the volume of crude oil that we transload, could materially and adversely affect our business and results of operations.

The natural gas volumes that support our midstream natural gas business are dependent on the level of production from crude oil and natural gas wells connected to our systems, the production of which will naturally decline over time. Likewise, the crude oil volumes that support our logistics business are dependent on the level of production from oil wells in our areas of operation. As a result, our cash flows associated with these wells will also decline over time unless we obtain new sources of natural gas and crude oil to maintain or increase throughput and transloading volumes. The primary factors affecting our ability to obtain non-dedicated sources of natural gas and crude oil include (i) the level of successful drilling activity in our areas of operation, (ii) our or AES's ability to compete for volumes from successful new wells or from wells in which existing contractual arrangements with us and our competitors are expiring and (iii) our or AES's ability to compete successfully for volumes from sources connected to other pipelines. Neither we nor AES have control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, neither we nor AES have control over producers or their drilling or production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected commodity prices, including the prices of crude oil, natural gas and NGLs;
- demand for crude oil, natural gas and NGLs;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other production and development costs.

Fluctuations in energy prices can also greatly affect the development of new crude oil and natural gas reserves. Drilling and production activity generally decreases as crude oil and natural gas prices decrease. In general terms, the prices of natural gas, crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- worldwide economic and political conditions;
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;
- the availability of imported liquefied natural gas, or LNG;
- the ability to export LNG;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials and premiums;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of crude oil, natural gas, LNG and other commodities.

Because of these factors, even if new natural gas or crude oil reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. Further declines in natural gas prices could have a negative impact on exploration, development and production activity, and if sustained, could lead to a material decrease in such activity. Sustained reductions in exploration or production activity in our areas of operation would lead to reduced utilization of our assets. If reductions in this activity result in our inability to maintain the current levels of natural gas throughput on our systems and the volumes of crude oil that we transload, it could reduce our revenues and cash flows and materially and adversely affect our ability to make cash distributions to our unitholders.

If credits under certain third-party material gathering, processing and transportation agreements exist, and cash reserves are not made for potential application of the credits to shortfalls on future minimum commitments, or if the customer is able and elects to use any applicable credits upon the expiration or termination of such agreement, actions taken by our general partner may affect the amount of cash available to unitholders or accelerate the conversion of subordinated units.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner. These decisions may include whether cash received in connection with surplus volumes above minimum volume commitments with significant third-party customers, including Anadarko, may result in lower fees, and therefore less cash received, in future periods as credits are applied against future minimum volume commitments.

Distributions of available cash relating to surplus volumes in earlier periods may have the purpose or effect of (1) enabling our general partner or its affiliates to receive distributions on either subordinated units or IDR Units held by them, or (2) accelerating the conversion of subordinated units.

If our customers do not increase the volumes of natural gas and crude oil they provide to our gathering and processing facilities or transloading facilities, our growth strategy and ability to increase cash distributions to our unitholders may be materially and adversely affected.

Our ability to increase the throughput on our gathering and processing facilities and the volumes of crude oil that we transload at our transloading facilities is dependent on receiving increased volumes from our existing customers, including AES. Our customers, including AES, are not obligated to provide additional volumes to our gathering and processing systems or to our transloading facilities, and they may determine in the future that areas outside of our current areas of operation are strategically more attractive to them.

A decrease in demand for natural gas, NGLs or condensate by the petrochemical, refining, agricultural, or electric power industries, or a decrease in demand for crude oil, could materially and adversely affect the profitability of our midstream energy business.

A decrease in demand for natural gas, NGLs or condensate by the petrochemical, refining, agricultural or electric power industries, could materially and adversely affect the profitability of our midstream natural gas business. Various factors impact the demand for natural gas, NGLs and condensate, including general economic conditions, extended periods of ethane rejection, which can occur when the price of ethane is less than the price of methane, increased competition from petroleum-based products due to pricing differences, adverse weather conditions, availability of natural gas processing and transportation capacity and government regulations affecting prices and production levels of natural gas, NGLs and condensate. Likewise, a decrease in demand for crude oil could materially and adversely affect the profitability of our crude oil logistics business. The volume of crude oil we transload depends on the availability of attractively priced crude oil produced or received in the areas serviced by our crude oil logistics assets. A period of sustained increases in the price of crude oil in areas serviced by our crude oil logistics assets, as compared to alternative sources of crude oil available to our customers, could materially reduce demand for crude oil in these areas. As a result, the volumes of crude oil that we transload at our transloading facilities could decline.

Significant prolonged changes in natural gas prices or NGL prices could affect supply and demand, reducing throughput on our midstream natural gas systems and materially and adversely affecting our revenues and distributable cash flow over the long-term.

We operate in the midstream energy industry. As such, changes in the prices of hydrocarbon products and in the relative price levels among hydrocarbon products could have a material adverse effect on our financial position, results of operations and cash flows. Changes in prices may impact demand for hydrocarbon products, which in turn may impact production, demand and the volumes of products for which we provide services. In addition, decreases in

demand may be caused by other factors, including prevailing economic conditions, reduced demand by consumers for the end products made with hydrocarbon products, increased competition, adverse weather conditions and government regulations affecting prices and production levels.
In recent years, the prices of crude oil and natural gas have been volatile, and we expect this volatility to continue. During the fourth quarter of 2014, crude oil prices based on WTI dropped sharply to a low of $53.27 per barrel, reflecting a

decline from an average of $94.20 per barrel in 2012 and $97.97 per barrel in 2013 and a high of $107.26 per barrel earlier in 2014. WTI crude oil prices averaged $47.33 per barrel in January 2015. The New York Mercantile Exchange ("NYMEX") daily settlement price for natural gas for the prompt month futures contract ranged: in 2012, from a high of $3.90 per MMBtu to a low of $1.91 per MMBtu; in 2013, from a high of $4.46 per MMBtu to a low of $3.11 per MMBtu; and in 2014, from a high of $6.15 per MMBtu to a low of $2.89 per MMBtu.

Generally, prices of hydrocarbon products are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of other uncontrollable factors, such as: (i) the level of domestic production and consumer product demand; (ii) the availability of imported oil and natural gas and actions taken by foreign oil and natural gas producing nations; (iii) the availability of transportation systems with adequate capacity; (iv) the availability of competitive fuels; (v) fluctuating and seasonal demand for oil, natural gas, NGLs and other hydrocarbon products, including demand for NGL products by the petrochemical, refining and heating industries; (vi) the impact of conservation efforts; (vii) governmental regulation and taxation of production; and (viii) prevailing economic conditions.

The natural gas, NGLs and crude oil currently transported, gathered or processed at our facilities originate from existing domestic resource basins, which naturally deplete over time. To offset this natural decline, our facilities will need access to production from newly discovered properties. Many economic and business factors beyond our control can adversely affect the decision by producers to explore for and develop new reserves. These factors could include relatively low commodity prices, cost and availability of equipment and labor, regulatory changes, capital budget limitations, the lack of available capital or the probability of success in finding hydrocarbons. A decrease in exploration and development activities in the regions where our facilities and other energy logistic assets are located could result in a decrease in our volumes, which could have a material adverse effect on our financial position, results of operations and cash flows.

A sustained decline could also potentially affect the ability of our vendors, suppliers and customers to continue operations. In addition, the natural gas volumes that we obtain from customers that are natural gas marketers, such as AES, are adversely impacted by low NGL prices, particularly for ethane, due to less favorable NGL sale economics for such marketers in low NGL price environments. Furthermore, higher natural gas and NGL prices over the long-term could result in a decline in the demand for natural gas and NGLs and, therefore, in the throughput on our midstream natural gas systems.

As a result, significant prolonged changes in natural gas or NGL prices could materially and adversely affect our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

If third-party pipelines or other midstream facilities interconnected to our gathering and processing facilities become partially or fully unavailable, or if the volumes we gather, process or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and gross margin and our ability to make cash distributions to our unitholders could be materially and adversely affected.

Our natural gas gathering and processing and transportation assets are dependent upon third-party pipelines and other facilities for natural gas supply and NGL takeaway capacity. For example, our Tyler County processing facility is entirely dependent on volumes received from a gathering system owned and operated by an affiliate of Anadarko. In addition, our only NGL transportation option is TEPPCO Partners, L.P.'s Panola Pipeline. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from hurricanes or other operational hazards. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurred, if any of these pipelines or other midstream facilities becomes unable to receive or transport natural gas or NGLs, or if the volumes we gather or transport do not meet the natural gas quality requirements of such pipelines or facilities, our revenues and gross margin and our ability to make cash distributions to our unitholders could be materially and adversely affected.

Our right of first offer on certain of Azure's midstream assets is subject to risks and uncertainty, and ultimately we may not acquire any of those assets.

In connection with the closing of the Transactions, we terminated our prior omnibus agreement and entered into the New Omnibus Agreement with our general partner and Azure, pursuant to which, among other thing, we have a right of first offer on any proposed transfer of any assets owned by Azure or its subsidiaries as of January 14, 2015.

We can provide no assurance whether, when or on what terms we will be able to successfully consummate any future acquisitions pursuant to our right of first offer, and Azure is under no obligation to accept any offer that we may choose to make or to enter into any commercial agreements with us. For these or a variety of other reasons, we may decide not to exercise our right of first offer when we are permitted to do so, and our decision will not be subject to unitholder approval. In addition, our right of first offer may be terminated by Azure at any time after it no longer controls our general partner. For additional information relating to our right of first offer, please see Item 13 “Certain Relationships and Related Party Transactions—Omnibus Agreement” included in this Form 10-K.

The long-term growth of our logistics business is substantially dependent on the availability of railcars.

We do not own or maintain a fleet of railcars, and the long-term growth of our crude oil logistics business is substantially dependent on the availability of railcars to transport crude oil received by our transloaders. The availability of such railcars is not within our control and they may become unavailable due to increased demand more stringent safety requirements, or other logistical constraints. AES, our sole transloading customer, has in the past experienced periods of railcar shortages, and may experience such shortages in the future. If AES is unable to obtain a sufficient supply of railcars to enable us to transload the crude oil delivered to us by AES, our business and results of operations could be materially and adversely affected.

Our success depends on drilling activity and our ability to attract and maintain customers in a limited number of geographic areas.

A significant portion of our assets are located in East Texas, the Uinta Basin and the Powder River Basin, and we intend to focus our future capital expenditures substantially on developing our business in these areas. As a result, our financial condition, results of operations and cash flows are significantly dependent upon the demand for our services in these areas. Due to our focus on these areas, an adverse development in natural gas or crude oil production from these areas would have a significantly greater impact on our financial condition and results of operations than if we spread expenditures more evenly over a wider geographic area. For example, a change in the rules and regulations governing operations in or around the East Texas area, the Uinta Basin or the Powder River Basin could cause producers to reduce or cease drilling operations or to permanently or temporarily shut-in their production within the area, which could materially and adversely affect our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties, and any material nonpayment or nonperformance by one or more of these parties could materially and adversely affect our financial condition and results of operations.

Any inaccuracies, miscalculations or declines in the creditworthiness of our customers, suppliers and contract counterparties may have an adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. There can be no assurance that our counterparties will perform or adhere to existing or future contractual arrangements. In addition, there can be no assurance that our assessments as to the creditworthiness of our customers, suppliers and contract counterparties will be accurate or that such creditworthiness will not deteriorate in a rapid and/or unanticipated manner.

The procedures and policies we use to manage our exposure to counterparty credit risk, such as credit analysis, credit monitoring and, in some cases, requiring credit support, cannot fully eliminate counterparty credit risks. To the extent our procedures and policies prove to be inadequate, our financial and operational results may be negatively impacted.

Some of our counterparties may be highly leveraged or have limited financial resources and will be subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with such parties. In addition, volatility in commodity prices might have an impact on many of our counterparties, which, in turn, could have a negative impact on their ability to meet their obligations to us and may also increase the magnitude of these obligations.

Any material nonpayment or nonperformance by our counterparties could require us to pursue substitute counterparties for the affected operations, reduce operations or provide alternative services, and there can be no assurance that any such efforts would be successful or would provide similar financial and operational results. If we are unable to adequately mitigate the risk of nonpayment or nonperformance by our counterparties, our business, financial condition, results of operations and ability to make cash distributions to our unitholders may be materially and adversely affected.

We intend to grow our business in part by seeking strategic acquisition opportunities. If we are unable to make acquisitions on economically acceptable terms, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our distributable cash flow on a per unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our distributable cash flow on a per unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could materially and adversely affect our ability to grow our operations and increase our distributions to our unitholders.

If we are unable to make accretive acquisitions, whether because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (ii) unable to obtain financing for these acquisitions on economically acceptable terms, (iii) outbid by competitors or (iv) unable to obtain necessary governmental or third-party consents or for any other reason, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in our distributable cash flow on a per unit basis.

Any acquisition, whether from third parties or affiliates, involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenues and costs, including synergies and potential growth;
- an inability to secure adequate customer commitments to use the acquired systems or facilities;
- the risk that natural gas or crude oil reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the assumption of unknown liabilities;
- coordinating geographically disparate organizations, systems and facilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new geographic areas and business lines; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

The success of the Transactions may present challenges and cannot be assured.

Following the consummation of the Transactions, Azure controls us through its ownership of all of the equity interests in our general partner. In connection with the Closing, we entered into the New Omnibus Agreement with the general partner, which among other things, states that Azure will provide corporate, general and administrative services on behalf of the general partner for the benefit of us and our subsidiaries. Accordingly, following the Transactions, we are controlled by Azure rather than NuDevco.

The transition of the management of a business requires coordination of the personnel of both businesses, involves the integration of systems, applications, policies, procedures, business processes and operations and is a complex, costly and time-consuming process. There are difficulties inherent in this process, which include, but are not limited to, the following:

- the challenges of managing and operating a business and assets with a new set of management;
- consolidating corporate and administrative infrastructures;
- preserving the research and development and other important relationships of the businesses;
- appropriately managing unfamiliar assets and liabilities;
- diverting management's attention from ongoing business concerns; and
- coordinating geographically separate assets.

The transition process could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to familiarizing themselves with the business and operations previously under the control of NuDevco, which will decrease the time they will have to manage our business, service existing customers, attract new customers and develop new products or strategies. If our senior management is not able to effectively manage this process, or if any significant business activities are interrupted as a result of this process, our business could suffer.

Our construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

One of the ways that we intend to grow our midstream natural gas business is through organic growth projects. The construction of additions or modifications to our existing systems and the construction of new midstream natural gas assets involve numerous regulatory, environmental, political, legal and economic uncertainties that are beyond our control. Such expansion projects may also require the expenditure of significant amounts of capital, and financing may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project.

For instance, if we expand a pipeline, the construction may occur over an extended period of time, yet we will not receive any material increases in revenues until the project is completed and placed into service. Moreover, we could construct facilities to capture anticipated future growth in production in a region where such growth does not materialize or only materializes over a period materially longer than expected. Since we are not engaged in the exploration for and development of natural gas and crude oil reserves, we often do not have access to third-party estimates of potential reserves in an area prior to constructing facilities in that area. To the extent we do have such information and rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not attract enough throughput to achieve our expected investment return, which could materially and adversely affect our results of operations and financial condition.

In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights-of-way or federal and state environmental permits or other authorizations. Such authorization may not be granted or, if granted, such authorization may be approved on a delayed basis or include burdensome or expensive conditions. As a result, we may be unable to obtain such rights-of-way on a timely basis, if at all, and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or authorizations or to modify existing rights-of-way or authorizations. If the cost of modifying or obtaining new rights-of-way or authorizations increases materially, our cash flows could be materially and adversely affected.

Our growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow.

We continuously consider and enter into discussions regarding potential acquisitions or growth capital expenditures. Any limitations on our access to new capital will impair our ability to execute this strategy. If the cost of capital becomes too expensive, our ability to develop or acquire strategic and accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, including our then current unit price, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders.

Weak economic conditions and the volatility and disruption in the financial markets could increase the cost of raising money in the debt and equity capital markets while also diminishing the availability of funds from those markets. In addition, we are experiencing increased competition for the types of assets we contemplate purchasing. Weak economic conditions and competition for asset purchases could limit our ability to fully execute our growth strategy.

We do not intend to obtain independent evaluations of natural gas or crude oil reserves connected to our gathering and transportation assets or serviced by our crude oil logistics assets on a regular or ongoing basis; therefore, in the future, volumes of natural gas on our systems and volumes of crude oil served by our crude oil logistics assets could be less than we anticipate.

We do not intend to obtain independent evaluations of natural gas or crude oil reserves connected to our systems or served by our crude oil logistics assets on a regular or ongoing basis. Moreover, even if we did obtain such independent evaluations of natural gas or crude oil reserves, such evaluations may prove to be incorrect. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of crude oil and natural gas and assumptions concerning future crude oil and natural gas prices, future production levels and operating and development costs. Accordingly, we may not have independent estimates of total reserves dedicated to some or all of our systems and assets or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering and transportation assets or served by our crude oil logistics assets are less than we anticipate and we are unable to secure additional sources of natural gas or crude oil, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our businesses involve many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, our operations and financial results could be materially and adversely affected.

Our midstream natural gas operations are subject to all of the risks and hazards inherent in the gathering, compressing, treating and processing of natural gas and transportation of NGLs, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas and other petroleum hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in property and natural resource damage, personal injury and loss of life, pollution and suspension of operations.

In addition, our crude oil logistics operations are subject to all of the risks and hazards inherent in the transloading of crude oil, including:

- damage to transloading facilities, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;
- spills of crude oil and other hydrocarbons as a result of operator error or the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in property and natural resource damage, personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of facilities and equipment and pollution or other environmental or natural resource damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. In addition, although we are insured for environmental pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could materially and adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, when future acquisitions are made, we may be unable to recover from the prior owners, pursuant to negotiated contractual indemnification rights, for potential environmental liabilities.

A change in the jurisdictional characterization or regulation of our assets by federal, state or local regulatory agencies or a change in policy by those agencies could result in increased regulation of our assets which could materially and adversely affect our financial condition, results of operations and cash flows.

Our natural gas gathering operations are generally exempt from regulation by FERC under the Natural Gas Act of 1938, or NGA, but FERC regulation still affects these businesses and the markets for products derived from these businesses. FERC’s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, rate-making, capacity release and market center promotion, indirectly affect intrastate markets. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity. In addition, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of extensive litigation; accordingly, the classification and regulation of some of our pipelines may be subject to change based on future determinations by FERC, the courts or Congress.

State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, complaint-based rate regulation and nondiscriminatory take requirements. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels because FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and as a number of such companies have transferred gathering facilities to unregulated affiliates. The Railroad Commission of Texas, or TRRC, has adopted regulations that generally allow natural gas producers and shippers to file complaints with the TRRC in an effort to resolve grievances relating to intrastate pipeline access and rate discrimination. Our natural gas gathering operations could be materially and adversely affected in the future should they become subject to the application of state or federal regulation of rates and services. Our gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect our business. For additional information relating to the regulations to which we are subject, please see Items 1 and 2 - "Business and Properties—Regulation of Operations" included in this Form 10-K.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and related repairs.

Pursuant to authority under the NGPSA and HLPSA, as amended by the Pipeline Safety Improvement Act of 2002, the PIPES Act, and the 2011 Pipeline Safety Act, PHMSA, has adopted regulations requiring pipeline operators to develop integrity management programs for certain gas and hazardous liquid pipelines located where a leak or rupture could harm "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high population areas, areas that are sources of drinking water, and unusually sensitive ecological areas. These regulations require operators of covered pipelines, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing PHMSA regulations for intrastate gathering and transmission lines. Texas, where we conduct our operations, has developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. We currently estimate an annual average cost of $0.1 million for the years 2015 and 2016 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This estimate does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency was seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 report to Congress, the GAO acknowledged PHMSA's continued assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline

Safety Act directs the Secretary of Transportation to promulgate regulations relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, material strength testing and verification of the maximum allowable pressure of certain pipelines.
In addition, PHMSA has issued Advisory Bulletins which, among other things, advise pipeline operators to review whether existing records of the operating parameters and conditions of their pipelines are able to provide adequate support for determining whether such pipelines are operating at a safe pressure. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing, could increase our costs or result in reductions of allowable operating pressures. The 2011 Pipeline Safety Act and implementing regulations also increase the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as other pipeline safety legislation or any implementation of PHMSA rules thereunder could require us to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could and have a material adverse effect on our results of operations or financial position.
We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.
Our natural gas gathering, compression, treating, processing and transportation operations, NGL transportation operations and transloading operations are subject to stringent and complex federal, state and local environmental laws and regulations that govern the discharge of materials into the environment or otherwise relate to environmental protection.
These environmental laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations, or existing at our owned operation facilities. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations and the issuance of injunctions limiting or preventing some or all of our operations. In addition, we may experience a delay in obtaining or be unable to obtain required permits, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenues.
There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to our handling of natural gas, NGLs, crude oil and other petroleum hydrocarbons, because of air emissions and product-related discharges arising out of our operations, and as a result of historical industry operations and waste disposal practices. Joint and several, strict liabilities may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of petroleum hydrocarbons or wastes on, under or from our facilities and pipelines, a few of which have been used for natural gas gathering, NGL transportation or crude oil transloading activities for a number of years. Private parties, including the owners of the properties through which our gathering or transportation systems pass or upon which our transloading facilities operate and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property and natural resource damages and fines or penalties for related violations of environmental laws or regulations. In addition, changes in environmental laws occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015, which proposes more stringent primary and secondary National Ambient Air Quality Standards for ozone of between

65 and 70 ppb. We may not be able to recover all or any of these costs from insurance. For additional information relating to the environmental matters associated with our business, please see Items 1 and 2 - "Business and Properties-Environmental Matters" included in this Form 10-K.

We do not own all of the land on which our midstream natural gas pipelines and facilities and transloading facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our midstream natural gas pipelines and facilities have been constructed, 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 pipelines are not properly located within the boundaries of such rights-of-way. Under the majority of our right-of-way contracts, we obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies until abandonment. However, certain of our right-of-way contracts are for a specified period of time. In addition, we do not own the sites on which our Wildcat, Big Horn and East New Mexico transloading facilities are located or where we conduct our transloading operations. We have a site access agreement at our Wildcat facility with a 12-year term expiring November 14, 2025, a site access agreement at our East New Mexico facility expiring July 31, 2015, and a rail siding lease and service agreement at our Big Horn facility that expires July 31, 2016.

Our loss of these rights, through our inability to renew right-of-way contracts, site access agreements or rail siding leases or otherwise, could materially and adversely affect our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

The adoption of climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the products and services we provide.

Based on its findings that emissions of GHG present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes, the EPA has adopted rules under the CAA that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. In addition, the EPA has adopted rules requiring the monitoring and annual reporting of GHG emissions from onshore processing, transmission and storage facilities, which include certain of our operations. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual GHG emissions reporting is currently required to include GHG emissions reporting beginning in the 2016 reporting year for certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. While Congress has from time to time considered adopting legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our or our oil and natural gas exploration and production customers' equipment and operations could require us or our customers to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs we gather and process or crude oil that we transport. For example, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

The JOBS Act contains provisions that, among other things, relax certain reporting requirements for emerging growth companies, including certain requirements relating to accounting standards and compensation disclosure. We are classified as an emerging growth company. For as long as we are an emerging growth company, which may be up to five full fiscal years, we will not be required to, among other things, (i) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes Oxley Act of 2002, (ii) comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (iii) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise, (iv) provide certain disclosures regarding executive compensation required of larger public companies or (v) hold unitholder advisory votes on executive compensation.

In addition, Section 107 of the JOBS Act also provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. In other words, an "emerging growth company" can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. We have elected to delay such adoption of new or revised accounting standards, and as a result, we may not comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for non-emerging growth companies. As a result of such election, our financial statements may not be comparable to the financial statements of other public companies.

Restrictions in our revolving credit facility could adversely affect our business, financial condition, results of operations, ability to make distributions to unitholders and value of our common units.

In connection with the Transaction, we entered into a new revolving credit facility (the "Credit Facility"). The credit agreement governing our Credit Facility limits our ability to, among other things: (a) incur additional debt; (b) grant certain liens; (c) make certain investments; (d) engage in certain mergers or consolidations; (e) dispose of certain assets; (f) enter into certain types of transactions with affiliates; (g) make distributions, with certain exceptions, including the distribution of Available Cash (as defined in the Partnership Agreement) if no default or event of default exists and, during the Availability Period (as defined in the credit agreement), if an Availability deficiency exists, the aggregate amount of distributions of Available Cash made during such deficiency shall not exceed $10 million; (h) enter into certain restrictive agreements or amend certain material agreements and (i) prepay certain debt.

The terms of the credit agreement require that our ratio of Consolidated Funded Indebtedness (as defined in the credit agreement) on the date of determination to Adjusted Consolidated EBITDA (as defined in the credit agreement) for a trailing four fiscal quarter period not exceed 4.50 to 1.00 (or 5.00 to 1.00 for the period commencing on the date that a certain acquisition is consummated through the last day of the second full fiscal quarter following the date of such acquisition). In addition, the credit agreement requires our ratio of Adjusted Consolidated EBITDA for a trailing four fiscal quarter period to Consolidated Interest Expense (as defined in the credit agreement) for such period to be at least 2.50 to 1.00. For a more detailed description of the terms and conditions of the credit agreement, please see "Management's Discussion and Analysis of Financial Condition-Liquidity and Capital Resources."

Accordingly, the provisions of our credit agreement 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 default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.

Our level of indebtedness may increase thereby reducing our financial flexibility.

Concurrently with the Transactions, we entered into the Credit Facility. The credit agreement governing the Credit Facility permits commitments of up to $250 million. In connection with the Transaction, we immediately borrowed $180.8 million under our Credit Facility, of which $99.5 million was used to pay the Contribution, $63.0 million was used in connection with the Redemption, $15.0 million was used to repay the outstanding balance as of February 26, 2015 under our prior credit facility and $3.2 million was used to pay fees and expenses associated with our new Credit Facility. Accordingly, as of February 27, 2015, our current balance under our credit agreement is $180.8 million.

Our level of indebtedness 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 flows required to make interest payments on our debt;

- our increased vulnerability 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 depends upon, among other things, our future financial and operating performance, which is affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our results of operations are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.

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

Interest rates may increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key management personnel.

Our ability to operate our business and implement our strategies depends on the continued contributions of certain executive officers and key employees of our general partner, particularly I.J. "Chip" Berthelot, II, our new President and Chief Executive Officer. The loss of Mr. Berthelot or any of our other senior executives could materially and adversely affect our business. In addition, we believe that our future success will depend on our continued ability to attract and retain highly skilled management personnel with midstream energy industry experience, and competition for these persons in the midstream energy industry is intense.

A shortage of skilled labor in the midstream energy industry could reduce labor productivity and increase costs, which could have a material adverse effect on our business and results of operations.

The gathering, treating, processing and transporting of natural gas and NGLs and transloading of crude oil requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. We have from time to time encountered shortages for these types of skilled labor. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially and adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs with respect to our general partner’s and its affiliates’ employees, our results of operations could be materially and adversely affected.

The amount of cash we have available for distribution to holders of our common and subordinated units depends primarily on our cash flows rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

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

Terrorist attacks and threats, cyber-attacks, escalation of military activity in response to these attacks or acts of war could materially and adversely affect our business, financial condition or results of operations.

Terrorist attacks and threats, cyber-attacks, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. Future terrorist or cyber-attacks, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions affecting our customers may significantly affect our operations and those of our customers. Strategic targets, such as energy-related assets and transportation assets, may be at greater risk of future attacks than other targets in the United States. Disruption or significant increases in energy prices could result in government-imposed price controls. Any of these occurrences, or a combination of them, could materially and adversely affect our business, financial condition and results of operations.

Risks Inherent in an Investment in Us

Azure owns and controls our general partner, which has the sole responsibility for conducting our business and managing our operations. Our general partner has conflicts of interest with and owes limited fiduciary duties to us, and may favor our general partner’s and Azure’s interests to the detriment of us and our unitholders.

Azure owns and controls our general partner and will be responsible for the approval of all the officers and directors of our general partners. In connection with the Transactions, Azure agreed to retain W. Keith Maxwell III as a director of our general partner for as long as NuDevco and IDRH and their respective affiliates continue to beneficially own more than 33.33% of our outstanding common units and subordinated units.

Although our general partner has a fiduciary duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to its owner. Conflicts of interest may arise between our general partner and its affiliates, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interest of its affiliates over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our partnership agreement nor any other agreement requires our general partner and its affiliates to pursue a business strategy that favors us.
- Our general partner is allowed to take into account the interests of parties other than us in resolving conflicts of interest.
- Our partnership agreement limits the liability of and reduces the fiduciary duties owed by our general partner, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.
- 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 and the ability of the subordinated units to convert to common units.
- Our general partner determines which costs incurred by it are reimbursable by us.
- Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- Our partnership agreement permits us to classify up to $19.0 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 on our subordinated units or to our general partner in respect of the general partner interest or to Azure and NuDevco in respect of the IDR Units.
- 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.
- 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 IDR Units 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.

Azure and its affiliates are not limited in their ability to compete with us and, other than as provided in the New Omnibus Agreement, are not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could materially and adversely affect our results of operations and our ability to make cash distributions to our unitholders.

Azure and its affiliates are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, in the future, Azure or its affiliates may acquire, construct or dispose of additional midstream natural gas, crude oil logistics or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities, other than such

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obligations as set forth in the omnibus agreement that we entered into with Azure and our general partner at the closing of the Transactions. Moreover, except for the obligations set forth in the omnibus agreement, neither Azure nor any of its affiliates has a contractual obligation to offer us the opportunity to purchase additional assets from it, and we are unable to predict whether or when such an offer may be presented and acted upon.

Common units held by persons who are non-taxpaying assignees will be subject to the possibility of redemption.

Our partnership agreement gives our general partner the power to amend the agreement to avoid any adverse effect on the maximum applicable rates chargeable to customers by us under FERC regulations, or in order to reverse an adverse determination that has occurred regarding such maximum rate. If our general partner determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us, then our general partner may adopt such amendments to our partnership agreement as it determines are necessary or advisable to obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant) and permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our general partner to obtain proof of the U.S. federal income tax status.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner’s fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise 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.

Because we distribute all of our available cash to our unitholders, we expect to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, 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, we may not grow as quickly as 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, and in our revolving credit facility, 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.

Our partnership agreement limits our general partner’s fiduciary duties to holders of our common and subordinated units.

Our partnership agreement contains provisions that modify and reduce the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner or otherwise, free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its affiliates;

- whether to exercise its limited call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to elect to reset target distribution levels; and

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- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

Our partnership agreement restricts the remedies available to holders of our common and subordinated units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith, meaning that it believed that the decision was in the best interest of our partnership, taking into account the totality of the circumstances or the totality of the relationships between the parties involved, including other relationships or transactions that may be particularly favorable or advantageous to us;
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- provides that our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:

(1) approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

(2) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

(3) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

(4) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (3) and (4) above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Azure, as the owner of the majority of our IDR Units, may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related the IDR Units 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.

Azure, as the owner of the majority of our IDR Units, has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election by Azure, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as 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.

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We anticipate that Azure would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that Azure could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when Azure expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, Azure may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for Azure to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then current business environment. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to Azure in connection with resetting the target distribution levels related to the IDR Units.

Holders of our common units 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. For example, unlike holders of stock in a public corporation, unitholders do not have "say-on-pay" advisory voting rights. Unitholders 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 will be chosen by Azure subsequent to the closing of the Transactions. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. 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 the unitholders' ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

The unitholders are currently unable to remove our general partner without its consent. The vote of the holders of at least 66 $^2/_3$% of all outstanding limited partner units voting together as a single class is required to remove our general partner. NuDevco indirectly owns 60.2% of our outstanding common and subordinated units. Pursuant to the Unitholder Agreement, dated as of February 27, 2015, by and among Azure, the general partner, IDRH and NuDevco Midstream, NuDevco Midstream has agreed not to vote its common units in favor of the removal of the general partner or in favor of any immediate successor general partner.

Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would materially and adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholder's dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are 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 transferees and persons who acquired such units with the prior approval of the board of directors 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 unitholder consent.

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 the unitholders. Furthermore, our partnership agreement does not restrict the ability of Azure to transfer all or a portion of its 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.

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

Our partnership agreement does not limit the number of additional general partner interests or limited partner interests that we may issue at any time without the approval of our unitholders and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such general partner interests or limited partner interests. Further, there are no limitations in our partnership agreement on our ability to issue equity securities that are equal or senior to our common units with respect to distributions or liquidation preference or that have special voting rights and other rights. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash we have available to distribute on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- 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.

The issuance by us of additional general partner units will have the following effects, among others, if such general partner interests are issued to a person who is not an affiliate of Azure:

- our business will no longer be solely managed by our general partner's current owner, Azure;
- the newly admitted general partner may have sufficient ownership to be in a position to replace the board of directors and officers of our general partner with its own nominees; and
- affiliates of the newly admitted general partner may compete with us, and neither our general partner nor such affiliates will have any obligation to present business opportunities to us.

NuDevco or other large holders may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

At December 31, 2014, we had 8,979,248 common units and 8,724,545 subordinated units outstanding and NuDevco holds an aggregate of 1,939,265 common units and 8,724,545 subordinated units. NuDevco continues to own the common units and subordinated units following the Transactions. All of the subordinated units will convert into common units at the end of the subordination period and may convert earlier under certain circumstances. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

On February 27, 2015, we entered into a unitholder agreement with Azure and NuDevco whereby NuDevco and its affiliates have certain lock-up restrictions that limit NuDevco's ability to transfer its common and subordinated units. The lock-up restrictions state that NuDevco cannot transfer (i) any common and subordinated units for a period of 180 days subsequent to February 27, 2015, (ii) more than 25% of the common and subordinated units for a period of 270 days subsequent to February 27, 2015, (iii) more than 50% of the common and subordinated units for a period of one year subsequent to February 27, 2015 and (iv) more than 80% of the common and subordinated units for a period of two years subsequent to February 27, 2015.

Our general partner has a limited call right that may require unitholders to sell their 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 on their investment. Our unitholders may also incur a tax liability upon a sale of their units. NuDevco indirectly owns approximately 21.6% of our outstanding common units. At the end of the subordination period, assuming no additional issuances of common units (other than upon the conversion of the subordinated units), NuDevco will indirectly own approximately 60.2% of our outstanding limited partner units.

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The liability of our unitholders 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. Our unitholders could be liable for any and all of our obligations as if they 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
- our unitholders' 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.

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 Revised Uniform Limited Partnership Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. 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 interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service, or IRS, were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our distributable cash flow would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the 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 on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our operations that we are or will be so treated, a change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%, and would likely pay state and local income tax at varying rates. Distributions 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. Since a tax would be imposed upon us as a corporation, our distributable cash flow would be reduced substantially. Therefore, if we were treated as a corporation for federal income tax purposes there would be material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

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

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 distributable cash flow. 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 units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Fiscal Year 2016 Budget proposed by the President recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration’s proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. 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.

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

Our unitholders are required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive 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.

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 distributable cash flow.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. 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. A court may not agree with some or all of the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on 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 distributable cash flow.

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

If a unitholder sells common units, such unitholder will recognize gain or loss equal to the difference between the amount realized and the unitholder’s tax basis in those units. Because distributions in excess of the unitholder’s allocable share of our net taxable income decrease its tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units being sold will, in effect, become taxable income to the unitholder if it sells such units at a price greater than its tax basis in those units, even if the price received is less than the unitholder’s original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be 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 sells units, such unitholder may incur a tax liability in excess of the amount of cash received from the sale.

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

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

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

Due to a number of factors including our inability to match transferors and transferees of common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

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

We prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and although the U.S. Treasury Department issued proposed regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we will adopt. If the IRS were to challenge this method or new Treasury regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered to have disposed of those common units. If so, the 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 could recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned common units. In that case, the unitholder may 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 the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their common units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

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

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

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

As a result of investing in our common units, a unitholder 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, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We own property or conduct business in numerous states, most of which impose a personal income tax on individuals as well as an income tax on corporations and other entities. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose similar taxes. It is your responsibility to file all U.S. federal, state and local tax returns.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

We are not a party to any legal, regulatory or administrative proceedings other than proceedings arising in the ordinary course of our business. Management believes that there are no such proceedings for which final disposition could have a material adverse effect on our financial condition, results of operations or cash flows, or for which disclosure is required by Item 103 of Regulation S-K.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

MARKET INFORMATION

Our common units are listed on the NASDAQ Global Market under the symbol "FISH." The following table sets forth the high and low sales prices for the common units and the cash distribution per unit declared subsequent to our IPO.

2014	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
High Price	$18.66	$20.47	$21.80	$21.47
Low Price	$16.17	$17.10	$19.22	$16.53
Distribution per common unit	$0.355	$0.360	$0.365	$0.365
2013			Third Quarter (1)	Fourth Quarter
High Price			$20.25	$19.25
Low Price			$17.45	$15.93
Distribution per common unit (2)			$0.230	$0.350

(1) From August 8, 2013, the date our common units began trading on the NASDAQ Global Markets, through September 30, 2013.

(2) For the quarter ending September 30, 2013, the amount of the distribution was adjusted based on the net income of the Partnership for the period July 31, 2013 through September 30, 2013.

As of March 4, 2015, there were approximately 4 unitholders of record of the Partnership's common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. We have also issued 357,935 general partner units for which there is no established public trading market. All general partner units are held by our general partner.

OTHER SECURITIES MATTERS

Securities authorized for issuance under equity compensation plans.

In connection with the IPO, the board of directors of our general partner adopted the Marlin Midstream Partners, LP 2013 Long-Term Incentive Plan ("LTIP"). Individuals who are eligible to receive awards under the LTIP include (1) our employees and the employees of NuDevco Midstream Development and its affiliates, (2) directors of our general partner, and (3) consultants who perform services for us and our affiliates. The LTIP provides for the grant of unit options, unit appreciation awards, restricted units, phantom units, distribution equivalent rights, unit awards, profits interest units, and other unit-based awards. The maximum number of common units issuable under the LTIP is 1,750,000. As of December 31, 2014, 1,451,600 common units remained available for issuance under the LTIP.

As a result of the Transactions, the awards previously issued under the LTIP immediately vested due to the change in control of our general partner. Azure, as general partner, plans to continue to operate under the LTIP in the future. However, there were no awards issued under the LTIP in connection with or immediately following the closing of the Transactions, and Azure, as general partner, has the ability to determine the terms and conditions of the awards issued under the LTIP, which may differ from those previously issued.

SELECTED INFORMATION FROM THE PARTNERSHIP AGREEMENT

Distributable cash and distributions. The partnership agreement requires us to distribute all available cash to unitholders of record, as of the applicable record date, no later than 45 days after the end of each quarter.

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

•less the amount of cash reserves established by the general partner to:

provide for the proper conduct of the business (including reserves for future capital expenditures and anticipated future debt service requirements and for anticipated shortfalls on future minimum commitment payments to which prior credits may be applied);

comply with applicable law, any of our debt instruments or other agreements; or

provide funds for distributions to unitholders and to the general partner for any one or more of the next four quarters (provided that the general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);

- plus, if the general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

Under our current cash distribution policy, we intend to make at least the minimum quarterly distribution to the holders of our common units and subordinated units of $0.35 per unit, or $1.40 per unit on an annualized basis, to the extent we have sufficient available cash after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner and its affiliates. However, there is no guarantee that we will pay the minimum quarterly distribution on our units in any quarter. The amount of distributions paid under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

The following distributions to our general partner and limited partners were declared for the period from August 1, 2013 to December 31, 2014:

In Thousands, except per-unit amounts		Total Quarterly	Total	Date of
Quarter ended:		Distribution per Unit	Distribution (2)	Distribution
December 31, 2014		$0.365	$6,593	February 11, 2015
September 30, 2014		$0.365	$6,593	November 4, 2014
June 30, 2014		$0.360	$6,469	August 5, 2014
March 31, 2014		$0.355	$6,375	May 6, 2014
December 31, 2013		$0.350	$6,232	February 3, 2014
September 30, 2013	(1)	$0.230	$4,095	November 4, 2013

(1) This distribution represents a prorated amount of the full minimum quarterly distribution of $0.35 per unit for each whole quarter based on the number of days between the closing of our IPO on July 31, 2013 and September 30, 2013.
(2) Total distribution amount includes the distribution paid to our general partner and does not include the distribution equivalent rights ("DER") payment that accrue on all unvested phantom units that have been issued under our LTIP.

Item 6. Selected Financial Data
The following table shows our selected financial and operating data, which are derived from our consolidated and combined financial statements for the periods and as of the dates indicated. On July 31, 2013, we completed an initial public offering ("IPO") of 6,875,000 common units at a public offering price of $20.00 per common unit less an underwriting discount of $1.20 per common unit for net proceeds, before expenses, of $18.80 per common unit. Our former sponsor, NuDevco Partners, LLC ("NuDevco") also owns NuDevco Midstream Development, LLC ("NuDevco Midstream") and Associated Energy Services, LP ("AES"). In connection with the IPO, NuDevco and its affiliates conveyed Marlin Midstream, LLC ("Marlin Midstream") and Marlin Logistics, LLC ("Marlin Logistics") to us.

Additionally at the closing of the IPO, we issued 1,849,545 common units and 8,724,545 subordinated units to NuDevco Midstream Development. We terminated our commodity-based gas gathering and processing agreement with AES and assigned all our remaining keep-whole and other commodity-based gathering and processing agreements with third party customers to AES. We entered into transloading services agreements with AES, each with three year terms, minimum volume commitments and annual inflation adjustments. These transloading services agreements have been subsequently amended to extend their terms, including the minimum volume commitment, to February 27, 2020.

We also transferred to affiliates of our former sponsor (i) our 50% interest in a CO_2 processing facility located in Monell, Wyoming, (ii) certain transloading assets and purchase commitments owned by Marlin Logistics not currently under a service contract, (iii) certain property, plant and equipment and other equipment not yet in service and (iv) certain other immaterial contracts. The total net asset value transferred to the affiliates was $9.4 million. Additionally, NuDevco assumed $11.7 million of the non-current accounts payable balance owed by Marlin Midstream to affiliates of SEV and Marlin Midstream was released from such obligation.
The information in the following table should be read together with Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” included in this Form 10-K.

In thousands, except per-unit data and throughput	Summary Financial Information			
	2014	2013	2012	2011
Statement of Operations Data (for the year ended):				
Total Revenues	$75,228	$52,860	$51,049	$65,818
Total operating expenses	51,777	47,189	49,499	51,453
Operating income	23,451	5,671	1,550	14,365
Interest income (expense), net	(766)	(4,349)	(4,927)	(3,733)
Other income (expense), net	—	(48)	(828)	(2,156)
Income tax (expense) benefit	(553)	(88)	(101)	65
Net income (loss)	$22,132	$1,186	$(4,306)	$8,541
Key Performance Measures (for the year ended):				
Gross margin (1)	$57,880	$38,861	$30,026	$36,962
Adjusted EBITDA (1)	$34,231	$16,880	$9,239	$19,730
Distributable cash flow (1) (2)	$31,624	$12,982	n/a	n/a
Net income per limited partner common unit - basic	$1.23	$0.40		
Net income per limited subordinated unit - basic	$1.22	$0.40		
Net income per limited partner common unit - diluted	$1.21	$0.39		
Net income per limited subordinated unit - diluted	$1.22	$0.40		
Distributions declared per unit	$1.44	$0.58		
Balance Sheet Data (as of the year ended December 31)				
Net property, plant and equipment	$162,158	$162,548	$165,139	
Total assets	$171,838	$174,142	$180,796	
Total liabilities	$17,408	$13,592	$148,517	
Total equity and partners' capital	$154,430	$160,550	$32,279	
Cash Flow Data (for the year ended):				
Net cash flows provided by (used in):				
Operating activities	$33,264	$9,176	$11,214	$16,102
Investing activities	$(9,508)	$(12,710)	$(12,445)	$(25,658)
Financing activities	$(24,310)	$1,136	$6,355	$8,097
Operating data (for the year ended):				
Gas volumes (MMcf/d) (3)	203	219		
Transloading volumes (Bbls/d) (3)	20,473	18,980		

(1) Gross Margin, Adjusted EBITDA and Distributable Cash flow are not defined in the generally accepted accounting principles in the United States (“GAAP”). For additional information and a reconciliation of these measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, see Item 7 “Managements' Discussion and Analysis of Financial Condition and Results of Operations-How We Evaluate Our Operations” included in this Annual Report on Form 10-K.
(2) For the year ended December 31, 2013, distributable cash is prorated from our IPO on July 31, 2013 through December 31, 2013.
(3) Volumes reflect the minimum volume commitment under our fee-based contracts or actual throughput, whichever is greater, for the post-IPO period.

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

Unless the context otherwise requires, references in this report to “we,” “our,” “us,” or like terms, when used in a historical context, refer to the combined businesses and assets of Marlin Midstream and Marlin Logistics, and when used in the present tense or prospectively, refer to Marlin Midstream Partners, LP and its subsidiaries.

OVERVIEW

We are a fee-based, growth-oriented Delaware limited partnership formed to develop, own, operate and acquire midstream energy assets. We currently provide natural gas gathering, compression, dehydration, treating, processing and hydrocarbon dew-point control and transportation services, which we refer to as our midstream natural gas business, and crude oil transloading services, which we refer to as our crude oil logistics business. Our assets and operations are organized into the following two segments:

Midstream Natural Gas

As of December 31, 2014, our primary midstream natural gas assets primarily consisted of (i) two related natural gas processing plants located in Panola County, Texas with an aggregate approximate design capacity of 220 MMcf/d, (ii) a natural gas processing plant located in Tyler County, Texas with an approximate design capacity of 80 MMcf/d, (iii) two natural gas gathering systems connected to our Panola County processing plants that include approximately 65 miles of natural gas pipelines with an approximate design capacity of 200 MMcf/d, and (iv) two NGL transportation pipelines with an aggregate approximate design capacity of 20,000 Bbls/d that connect our Panola County and Tyler County processing plants to third party NGL pipelines. Our primary midstream natural gas assets are located in long-lived oil and natural gas producing regions in East Texas and gather and process NGL-rich natural gas streams associated with production primarily from the Cotton Valley Sands, Haynesville Shale, Austin Chalk and Eaglebine formations.

Additionally, in connection with the Transactions (as defined below), we acquired the Legacy System on February 27, 2015. The Legacy System is primarily located within Harrison, Panola and Rusk counties in Texas and Caddo parish in Louisiana and currently serves the Cotton Valley formation, the Haynesville shale formation and the shallower producing sands in the Travis Peak formation. The Legacy system consists of approximately 658 miles of high- and low-pressure gathering lines and served approximately 100,000 dedicated acres with access to seven major downstream markets, three third-party processing plants, and our Panola County processing facilities. The Legacy system has ten 1,340 horsepower compressors and two additional compressors comprising 725 horsepower, for a total of 14,125 horsepower of compression. The Legacy gathering system has an aggregate capacity of approximately 500 MMcf/d. The Legacy system gathers high-Btu natural gas with an NGL content between 2.0 and 5.2 GPM.

Logistics

As of December 31, 2014, our logistics assets consisted of three crude oil transloading facilities: (i) our Wildcat facility located in Carbon County, Utah, where we currently operate one skid transloader and two ladder transloaders, (ii) our Big Horn facility located in Big Horn County, Wyoming, where we currently operate one skid transloader and one ladder transloader, and (iii) our East New Mexico facility located in Sandoval County, New Mexico, where we currently operate one skid transloader. Our transloaders are used to unload crude oil from tanker trucks and load crude oil into railcars and temporary storage tanks. Our facilities provide transloading services for production originating from well-established crude oil producing basins, such as the Uinta and Powder River Basins, which we believe are currently underserved by our competitors. Our skid transloaders each have a transloading capacity of 475 Bbls/hr, and our ladder transloaders each have a transloading capacity of 210 Bbls/hr.

Sale of General Partner Interest and Contribution of the Legacy Gathering System

On February 27, 2015, we completed the transactions (the “Transactions”) described in detail below pursuant to a Transaction Agreement, dated January 14, 2015 (the “Transaction Agreement”), by and among us, Azure Midstream Energy LLC, a Delaware limited liability company (“Azure”), our general partner, NuDevco and Marlin IDR Holdings, LLC, a Delaware limited liability company and wholly-owned subsidiary of NuDevco (“IDRH”). Pursuant to the Transaction Agreement, we acquired the Legacy gathering system (the “Legacy System”) from Azure and Azure acquired all of the equity interests in our general partner and 90% of our IDR Units (as defined below) from NuDevco.

The following transactions were consummated on February 27, 2015, in connection with the closing of the Transactions (the “Closing”):

- we amended and restated our partnership agreement to reflect the unitization of our incentive distribution rights (as unitized, the “IDR Units”) and recapitalized the incentive distribution rights owned by IDRH into 100 IDR Units;

- we redeemed 90 IDR Units held by IDRH in exchange for a payment by us of $63 million to IDRH (the “Redemption”);

- we acquired the Legacy System from Azure through the contribution, indirectly or directly, of (i) all of the outstanding general and limited partner interests in Talco Midstream Assets, Ltd., a Texas limited liability company and subsidiary of Azure, and (ii) certain assets owned by TGG Pipeline, Ltd., a Texas limited liability company and subsidiary of Azure, in exchange for aggregate consideration of $162.5 million, which was paid to Azure in the form of $99.5 million in cash and by the issuance of 90 IDR Units (the foregoing transaction, collectively, the “Contribution”); and

- Azure purchased from NuDevco (i) all of the outstanding membership interests in the General Partner and (ii) an option to acquire up to 20% of our common and subordinated units held by NuDevco as of the execution date of the Transaction Agreement.

Following the consummation of the Transactions, Azure controls us through its ownership of all of the equity interests in our general partner from NuDevco. Our general partner controls us through its ownership of all of our outstanding general partner units, which represents an approximate 2% economic general partner interest in us. Azure also owns 90 IDR Units, which represent 90% of our IDR Units. NuDevco owns 60.2% of our outstanding limited partner interest and 10 IDR Units, which represent 10% of our incentive distribution rights.

Azure

Azure is a midstream company with a focus on owning, operating, developing and acquiring midstream energy infrastructure in core producing areas in the United States. Azure currently provides natural gas gathering, compression, treating and processing services in northern Louisiana and east Texas in the Haynesville and Bossier Shale formations. Prior to the Closing, Azure operated three main gathering systems: Holly, Center and Legacy. As described above, the Legacy System was contributed to the Partnership in connection with the Transactions. The two remaining gathering systems, Holly and Center, may potentially be available to the Partnership as future dropdown acquisitions, although Azure has no obligation to offer us those assets. Please see “Risk Factors-Risks Inherent in an Investment in Us- Azure and its affiliates are not limited in their ability to compete with us and, other than as provided in the New Omnibus Agreement, are not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could materially and adversely affect our results of operations and our ability to make cash distributions to our unitholders.”

General Trends and Outlook

In 2015, our strategic objectives will continue to be focused on maintaining stable distributable cash flows from our existing and newly acquired Legacy System and executing on growth opportunities to increase our long-term distributable cash flows. We believe the transformative combination of Azure’s substantial dropdown inventory, as well as Azure’s contribution of the Legacy System into our existing midstream assets, creates a diversified platform of midstream services and establishes us as one of the largest gathering and processing systems in the Haynesville and horizontal Cotton Valley plays in east Texas and north Louisiana.

The combination is expected to offer enhanced scale and diversification that provides additional financial flexibility that we anticipate will allow us to more effectively compete for greenfield development and acquisition opportunities across the midstream value chain. Further, the combination of a significant portfolio of long-term, fee-based contracts with high-quality producers, coupled with the potential for organic capital opportunities across multiple geographies, provides meaningful visibility to long-term growth. The complementary services offered by Azure are also expected to create attractive operational and financial synergies for both entities.

We believe the key elements to stable distributable cash flows are our significant fee-based business plus our assets that are strategically positioned to capitalize on drilling activity and related demand for midstream natural gas services. We expect to continue to pursue a multi-faceted growth strategy, which includes maximizing opportunities provided by our relationship with Azure, pursuing strategic and accretive third party acquisitions and capitalizing on organic expansion opportunities in order to grow our distributable cash flows.

HIGHLIGHTS

Significant financial highlights include the following:

- We declared and paid a distribution for the first four quarters of 2014 in the amounts of $0.355, $0.360, $0.365 and $0.365 per unit, respectively.
- Effective October 1, 2014, Associated Energy Services, LP ("AES"), an affiliated party, made their periodic election to increase their minimum volume commitment of 80 MMcf/d to 100 MMcf/d under its fee-based gas gathering and processing agreement with us.
- Upon closing of the Transactions, we entered into amendments to our (i) Wildcat Facility transloading services agreement, (ii) Big Horn transloading services agreement and (iii) Ladder transloading services agreement, all of which are transloading services agreements with AES. The amendments extend the minimum volume commitments associated with these services agreements until February 27, 2020, or five years from the date of the amendment.

Significant operational highlights include the following:

- On July 30, 2014, we entered into a Contribution Agreement with NuDevco Midstream Development and our general partner, for the purchase of the East New Mexico Transloading Facility, located in Sandoval County, New Mexico, for $7.4 million.
- We completed construction of our Longtail pipeline in March 2014 and the common inlet header between the Panola 1 and Panola 2 Processing Facilities in May 2014 for a total cost of $5.2 million. The combined projects created greater margin optimization by maximizing value of inlet gas for processing.

INITIAL PUBLIC OFFERING

On July 31, 2013, we completed an initial public offering ("IPO") of 6,875,000 common units at a public offering price of $20.00 per common unit less an underwriting discount of $1.20 per common unit for net proceeds, before expenses, of $18.80 per common unit. Additionally, at the closing of the IPO, we issued 1,849,543 common units and 8,724,545 subordinated units to NuDevco Midstream Development.

Following the closing of our IPO, we entered into fee-based commercial agreements with AES, substantially all of which include minimum volume commitments and annual inflation adjustments. We terminated our commodity-based gas gathering and processing agreement with AES and assigned all our remaining keep-whole and other commodity-based gathering and processing agreements with third party customers to AES. We entered into transloading services agreements with AES, each with three year terms, minimum volume commitments and annual inflation adjustments. These agreements have subsequently been amended to extend their initial terms. Please see Item 13. Certain Relationships and Related Party Transactions.

Our partnership agreement provides for a minimum quarterly distribution of $0.35 per unit for each whole quarter, or $1.40 per unit on an annualized basis.

As of the closing of the IPO, the unit ownership of outstanding units was as follows:

	Number of units at July 31, 2013	Partner Interest	
Publicly held common units	6,875,000	38.6	%
Common units held by NuDevco	1,849,545	10.4	%
Subordinated units held by NuDevco	8,724,545	49.0	%
General partner units	356,104	2.0	%
Total	17,805,194	100.0	%

At December 31, 2014, the unit ownership of outstanding units was as follows:

	Number of units at December 31, 2014	Partner Interest	
Publicly held common units	7,039,983	39.0	%
Common units held by NuDevco	1,939,265	10.7	%
Subordinated units held by NuDevco	8,724,545	48.3	%
General partner units	357,935	2.0	%
Total	18,061,728	100.0	%

HOW WE EVALUATE OUR OPERATIONS

Our management uses a variety of financial and operating metrics to analyze our performance. These metrics are significant factors in assessing our results of operations and profitability and include: (i) gross margin; (ii) volume commitments and throughput volumes (including gathering, plant, and transloader throughput); (iii) operation and maintenance expenses; (iv) adjusted EBITDA; and (v) distributable cash flow. Gross margin, adjusted EBITDA and distributable cash flow are not measures under accounting principles generally accepted in the United States of America, or GAAP. To the extent permitted, we present certain non-GAAP measure and reconciliations of those measures to their most directly comparable financial measure as calculated and presented in accordance with GAAP. These non-GAAP measures may not be comparable to a similarly titled measure of another company because other entities may not calculate these non-GAAP measures in the same manner.

In Thousands, except volume data	Years Ended December 31,		
	2014	2013	2012
Gross Margin	$57,880	$38,861	$30,026
Gas volumes (MMcf/d) (1)	203	219	
Transloading volumes (Bbls/d) (1)	20,473	18,980	
Adjusted EBITDA	$34,231	$16,880	$9,239
Distributable Cash Flow (2)	$31,624	$12,982	n/a

(1) Volumes reflect the minimum volume commitment under our fee-based contracts or actual throughput, whichever is greater, for the post-IPO period.

(2) For the year ended December 31, 2013, distributable cash is prorated from July 31, 2013 through December 31, 2013, the first applicable period in which distributions were made.

Gross Margin

Gross margin is a primary performance measure used by our management. We define gross margin as revenues less cost of revenues. Gross margin is a non-GAAP supplemental financial measure that represents our profitability with minimal exposure to commodity price fluctuations, which we believe are not significant components of our operations.

The following table presents a reconciliation of the non-GAAP financial measure of gross margin to the GAAP financial measure of operating income:

In Thousands	Years Ended December 31,		
	2014	2013	2012
Total operating income	$23,451	$5,671	$1,550
Operation and maintenance	8,899	12,401	15,035
Operation and maintenance-affiliates	6,668	3,490	793
General and administrative	3,602	3,699	3,045
General and administrative-affiliates	5,067	4,187	1,021
Property and other taxes	1,316	1,216	893
Depreciation expense	8,817	8,197	7,689
Loss on disposals of equipment	60	—	—
Gross Margin	$57,880	$38,861	$30,026

Volume Commitments and Throughput

We view the volumes of natural gas and crude oil committed to our midstream natural gas and crude oil logistics assets, respectively, as well as the throughput volume of natural gas and crude oil as an important factor affecting our profitability. The amount of revenues we generate primarily depends on the volumes of natural gas and crude oil committed to our midstream natural gas assets and crude oil logistics assets, respectively, our commercial agreements, the volumes of natural gas that we gather, process, treat and transport, the volumes of NGLs that we transport and sell, and the volumes of crude oil that we transload. Our success in attracting additional committed volumes of natural gas and crude oil and maintaining or increasing throughput is impacted by our ability to:

- utilize the remaining uncommitted capacity on, or add additional capacity to, our gathering and processing systems and our transloaders;
- capitalize on successful drilling programs by our customers on our current acreage dedications;
- increase throughput volumes on our gathering systems by increasing connections to other pipelines or wells;
- secure volumes from new wells drilled on non-dedicated acreage;
- attract natural gas and crude oil volumes currently gathered, processed, treated or transloaded by our competitors; and
- identify and execute organic expansion projects.

Adjusted EBITDA and Distributable Cash Flow

We use adjusted EBITDA to analyze our performance and define it as net income (loss) before interest expense (net of amounts capitalized) or interest income, income tax expense, depreciation expense, equity based compensation expense and any gain/loss from interest rate derivatives. Although we have not quantified distributable cash flow on a historical basis prior to the IPO, we compute and present this measure for periods subsequent to the IPO, which we define as adjusted EBITDA plus interest income, less cash paid for interest expense and maintenance capital expenditures.

Adjusted EBITDA and distributable cash flow are non-GAAP supplemental financial measures that management and external users of our condensed consolidated and combined financial statements, such as industry analysts, investors, commercial banks and others, may use to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate earnings sufficient to support our decision to make cash distributions to our unitholders and general partner;
- our ability to fund capital expenditures and incur and service debt;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

The following table presents a reconciliation of the non-GAAP financial measure of adjusted EBITDA to the GAAP financial measure of net income (loss):

In Thousands	Years Ended December 31,		
	2014	2013	2012
Net income (loss)	$22,132	$1,186	$(4,306)
Interest expense, net of amounts capitalized	766	4,349	4,927
Interest and other income	—	—	(23)
Income tax expense	553	88	101
Equity based compensation	1,963	3,012	—
Loss on interest rate swap	—	48	851
Depreciation expense	8,817	8,197	7,689
Adjusted EBITDA	$34,231	$16,880	$9,239

The following table presents a reconciliation of the non-GAAP financial measure of distributable cash flow to the GAAP financial measure of net income:

In Thousands	2014	For the period from July 31, 2013 to December 31, 2013
Net income	$22,132	$7,190
Add:		
Interest expense, net of amounts capitalized	766	352
Income tax expense	553	60
Depreciation expense	8,817	3,425
Equity based compensation	1,963	3,012
Adjusted EBITDA	34,231	14,039
Less:		
Maintenance capital expenditures	(1,384)	(782)
Cash interest expense	(510)	(215)
Income tax expense	(553)	(60)
Adjustment (1)	(160)	—
Distributable cash flow	$31,624	$12,982

(1) Removes the results of the East New Mexico Dropdown for the period prior to the acquisition (July 2, 2014 to July 31, 2014).

Gross margin, adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We believe that the presentation of these non-GAAP financial measures will provide useful information to investors in assessing our financial condition and results of operations.

The GAAP measure most directly comparable to gross margin is operating income. The GAAP measure most directly comparable to adjusted EBITDA and distributable cash flow is net income. These measures should not be considered as an alternative to operating income, net income, or any other measure of financial performance presented in accordance with GAAP. Each of these non-GAAP financial measures has important limitations as an analytical tool because it excludes some but not all items that affect net income. You should not consider these non-GAAP financial measures in isolation or as a substitute for analysis of our results as reported under GAAP. Additionally, because each of these non-GAAP financial measures may be defined differently by other companies in our industry, our definition of them may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

FACTORS AFFECTING THE COMPARABILITY OF OPERATING RESULTS

Our future results of operations may not be comparable to our historical results of operations for the reasons described below:

Revenues

There are differences in the way we generated revenues historically and the way we generate revenues subsequent to the closing of the Transactions and the IPO.

Gathering and Processing Agreements

- Beginning on January 1, 2012, our commercial agreements with Anadarko at our Panola County processing facilities were amended such that Anadarko began receiving the NGLs extracted on an in-kind basis. As a result, we do not sell the NGLs extracted under these amended agreements, and therefore the NGLs recovered under these amended agreements are not included in our natural gas, NGLs and condensate sales. Under our commercial agreements that do not require us to deliver NGLs to the customer in kind, including our gathering and processing agreement with AES that we entered into in connection with the closing of the IPO, we provide NGL transportation services to the customer whereby we purchase the NGLs from the customer at an index price, less fractionation and transportation fees, and simultaneously sell the NGLs to third parties at the same index price, less fractionation fees. The revenues generated by these activities are substantially offset by a corresponding cost of revenue that is recorded when we compensate the customer for its contractual share of the NGLs.
-

Subsequent to July 31, 2013, we assigned all of our existing commodity-based gathering and processing agreements with third party customers to AES and entered into a new three-year fee-based gathering and processing agreement with AES with a minimum volume commitment of 80 MMcf/d, which can be periodically increased. AES made their periodic election to increase the minimum volume commitment to 100 MMcf/d effective October 1, 2014.

- Subsequent to the closing of the Transactions on February 27, 2015, the revenues generated by us will include the revenues attributable to the Legacy System. The Legacy System's primary revenue producing activities are the sales of natural gas and NGLs purchased and the sale of condensate liquids. Natural gas revenues arise from transactions that are completed under contracts with limited commodity price exposure. The Legacy System receives a market price per barrel associated with natural gas condensate liquids sales. The Legacy System also earns gathering services and other fee based revenues from the gathering, compression and treating of natural gas. These gathering services and other fees are generally provided on a fixed fee basis per unit based on the volumes (MMcf/d) or heating content (MMBtu) of natural gas. Our results of operations will include the Legacy System from February 27, 2015 going forward and therefore may not be comparable to our historical results of operations regarding our gathering and processing segment.

Transloading Services Agreements

- Subsequent to July 31, 2013, our logistics revenues are generated under transloading services agreements that we entered into with AES at the closing of, or subsequent to, the IPO. Under the transloading services agreements with AES, we receive a per barrel fee for crude oil transloading services, including fees in respect of shortfall payments related to AES' minimum volume commitments under these agreements from time to time. Because our crude oil logistics assets did not become operational until 2013, our future results of operations will not be comparable to our historical results of operations regarding our crude oil logistics segment.
- On July 30, 2014, we entered into a Contribution Agreement with NuDevco Midstream Development and our general partner, for the purchase of the East New Mexico Transloading Facility, located in Sandoval County, New Mexico, for $7.4 million. Our results of operations will include the East New Mexico Transloading Facility from June 30, 2014 going forward.
- On February 27, 2015, we entered into amendments to our (i) Wildcat Facility transloading services agreement, (ii) Big Horn transloading services agreement and (iii) Ladder transloading services agreement, all of which are transloading services agreements with AES. The amendments extend the minimum volume commitments associated with these services agreements until February 27, 2020, or five years from the date of the amendment.

Operating and General and Administrative Expenses

With respect to our operation and maintenance expenses and general and administrative expenses, prior to the IPO, we employed all of our operational personnel and most of our general and administrative personnel directly, and incurred direct operating and general and administrative charges with respect to their compensation. In connection with the closing of the IPO, all of our personnel were transferred to affiliates of our general partner. As a result, following the closing of the IPO, we reimburse our general partner for the compensation of these employees on a direct or allocated basis, depending on whether those employees spend all or only a part of their time working for us. As a result of this change, the amount of our affiliate operation and maintenance expenses and affiliate general and administrative expenses will increase, and the amount of our non-affiliate operation and maintenance expenses and non-affiliate general and administrative expenses will decrease, compared to historical amounts. In addition, our general and administrative costs have increased due to the costs of operating as a publicly traded partnership.

Our historical general and administrative expenses included certain expenses allocated by affiliates of our general partner for general corporate services, such as information technology, treasury, accounting and legal services, as well as direct expenses. These allocated expenses were charged or allocated to us based on the nature of the expenses and our proportionate share of departmental usage, wages or headcount. After July 31, 2013, affiliates of NuDevco have continued to charge us a combination of direct and allocated monthly general and administrative expenses related to the management and operation of our midstream natural gas and crude oil logistics businesses and charge us an annual fee, initially in the amount of $0.6 million, for executive management services.

In connection with the Transactions, we entered into a new omnibus agreement with our general partner and Azure. Please see "Business and Properties-Sponsor Relationship."

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Financing

There are differences in the way we finance our operations as compared to the way we financed our operations on a historical basis prior to the IPO. Historically, our operations were financed by cash generated from operations, equity investments by our sole member and borrowings under our previous credit facility. In connection with the closing of the IPO, we repaid the full amount of our previous credit facility, settled our related interest rate swap liability and entered into a $50.0 million senior secured revolving credit facility. We had $11.0 million outstanding under our senior secured revolving credit facility as of December 31, 2014. Subsequent to December 31, 2014, we consummated the Transactions and entered into the Credit Facility. Please see "Liquidity and Capital Resources - Credit Facility." As of February 27, 2015 we had $180.8 million outstanding on the Credit Facility.

Based on the terms of our cash distribution policy, we expect that we will distribute to our unitholders and our general partner most of the cash generated by our operations. As a result, we expect to fund future capital expenditures primarily from external sources, including borrowings under our Credit Facility and future issuances of equity and debt securities.

RESULTS OF OPERATIONS

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

The following table presents selected financial data for each of the years ended December 31, 2014 and 2013.

In Thousands	Years ended December 31, 2014	2013	Change	% Change
REVENUES:				
Natural gas, NGLs and condensate revenue	$13,569	$15,792	$(2,223)	(14.1)%
Gathering, processing, transloading and other revenue	61,659	37,068	24,591	66.3%
Total Revenues	75,228	52,860	22,368	42.3%
OPERATING EXPENSES:				
Cost of natural gas, NGLs and condensate revenue	17,348	13,999	3,349	23.9%
Operation and maintenance	15,567	15,891	(324)	(2.0)%
General and administrative	8,669	7,886	783	9.9%
Property tax expense	1,316	1,216	100	8.2%
Depreciation expense	8,817	8,197	620	7.6%
Loss on disposals of equipment	60	—	60	100.0%
Total operating expenses	51,777	47,189	4,588	9.7%
Operating income	23,451	5,671	17,780	313.5%
Interest expense, net of amounts capitalized	(766)	(4,349)	3,583	(82.4)%
Loss on interest rate swap	—	(48)	48	(100.0)%
Net income (loss) before tax	$22,685	$1,274	$21,411	(1,680.6)%
Income tax expense	553	88	465	528.4%
Net income (loss)	$22,132	$1,186	$20,946	1,766.1%
Key performance metrics:				
Gross margin (1)	$57,880	$38,861	$19,019	48.9%
Adjusted EBITDA (1)	$34,231	$16,880	$17,351	102.8%
Volumes:				
Processing Facilities (MMcf/d) (2)	203	219	(16)	(7.3)%
Transloading Facilities (BBls/d) (2)	20,473	18,980	1,493	7.9%

(1) Gross Margin and Adjusted EBITDA are non-GAAP financial measures. For additional information and a reconciliation of these measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-How We Evaluate Our Operations."

(2) Volumes reflect the minimum volume commitment under our fee-based contracts or actual throughput, whichever is greater, for the post-IPO period.

Revenues. Natural gas, NGLs and condensate revenue decreased by $2.2 million, or 14%, to $13.6 million for the year ended December 31, 2014 from $15.8 million for the year ended December 31, 2013. The decrease in natural gas, NGLs and condensate revenue of $3.4 million for the year ended December 31, 2014 compared to the year ended December 31, 2013 is primarily due to a decrease in net NGL barrels sold under third-party purchase contracts. This decrease is partially offset by an increase in NGL prices. Increasing NGL prices in mid 2014 attributed to an approximate $1.9 million increase in our NGL sales for the year ended December 31, 2014 as compared to the year ended December 30, 2013.

Gathering, processing, transloading and other revenue increased by $24.6 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013, primarily from our minimum volume commitment agreements with Anadarko and AES and the escalation of prices on existing agreements. On July 31, 2013, we entered into a three-year fee-based gathering and processing agreement with AES with a minimum volume commitment and annual inflation adjustments.

For the year ended December 31, 2014, we recorded $22.7 million in gathering, processing, transloading and other revenue as a result of this contract, as compared to $7.2 million for the year ended December 31, 2013.
On July 31, 2013, we entered into three-year transloading services agreements with AES, requiring minimum monthly volume commitments for crude oil transloading services. In connection with the East New Mexico Dropdown, the Partnership entered into a three-year transloading services agreement with AES, requiring minimum monthly volume commitments for crude oil transloading services. For the year ended December 31, 2014, we recorded $15.3 million in gathering, processing, transloading and other revenue as a result of these contracts, as compared to $5.8 million for the year ended December 31, 2013. These increases are net against a decrease of $0.4 million in gathering, processing, transloading and other revenue, primarily a result of decreased volumes under third-party fee-based agreements.
Cost of Revenues. Cost of revenues are derived primarily from the creation of natural gas, NGLs and condensate revenue. Total cost of natural gas, NGLs and condensate revenue increased by $3.3 million, or 24%, to $17.3 million for the year ended December 31, 2014 as compared to $14.0 million for the year ended December 31, 2013. The increase is primarily due to the purchase of NGLs under our gathering and processing agreement with AES. During the year ended December 31, 2014, we purchased $12.6 million of NGLs from AES, as compared to $2.5 million purchases of NGLs from AES during the year ended December 31, 2013, resulting in an increase of $10.1 million in cost of natural gas, NGLs and condensate revenue.
This increase is offset by an approximate decrease of $3.3 million in cost of natural gas, NGLs, and condensate revenue, related to purchases of NGLs under short-term third-party purchase contracts during the year ended December 31, 2013. No such purchases were made during the year ended December 31, 2014.
In addition, we recorded $3.0 million of affiliate cost of revenues during the year ended December 31, 2013, primarily related to the purchase of natural gas from an affiliate of NuDevco under certain keep-whole agreements. The volume of gas redelivered or sold at the tailgates of our processing facilities is lower than the volume received or purchased at delivery points on our gathering systems or interconnecting pipelines due to the NGLs extracted when the natural gas is processed. On July 31, 2013, we were required to make up or “keep the producer whole” for the condensate and NGL volumes extracted from the natural gas stream through the delivery of or payment for a thermally equivalent volume of residue gas. Under certain keep-whole agreements, we purchased natural gas from an affiliate of NuDevco in order to make up or “keep the producer whole” for the condensate and NGL volumes extracted from the natural gas stream during processing. After July 31, 2013, we assigned all of our keep-whole agreements to AES. The remaining decrease of approximately $0.3 million is primarily related to lower volumes of redelivered gas at the tailgate of our plant during the year ended December 31, 2014 as compared to the year ended December 31, 2013.
Operation and Maintenance Expense. Operation and maintenance expense decreased by $0.3 million, or 2.0%, for the year ended December 31, 2014 as compared to the year ended December 31, 2013 primarily due to a decrease in chemical costs and external contract labor expenses in our midstream natural gas segment of $1.2 million. These decreases were offset by a $0.9 million increase primarily due to higher personnel and overhead costs. Operation and maintenance expenses are primarily composed of expenses related to labor, utilities and chemicals, property insurance premiums, compression costs and maintenance and repair expenses, which generally remain relatively stable across broad ranges of throughput volumes but can fluctuate from period to period depending on the mix of activities performed during the period and the timing of these expenses.
General and Administrative Expense. General and administrative expense increased by approximately $0.8 million, or 10%, to $8.7 million for the year ended December 31, 2014 as compared to $7.9 million for the year ended December 31, 2013. The increase is primarily due to increased Sarbanes-Oxley compliance costs and other non-recurring professional and legal fees associated with the August 1, 2014 dropdown of the Eastern New Mexico transloading facility and the announced transaction with Azure.
Depreciation Expense. Depreciation expense increased by approximately $0.6 million, or 7.6%, to $8.8 million for the year ended December 31, 2014 as compared to $8.2 million for the year ended December 31, 2013. Depreciation expense increase as a result of expanding our asset base.
Interest Expense. Interest expense, net of amounts capitalized, decreased by approximately $3.6 million to $0.8 million for the year ended December 31, 2014 as compared to $4.3 million for the year ended December 31, 2013. The decrease in interest expense was primarily associated with the 2013 write-off of deferred loan costs associated

with our previous credit facilities in connection with the IPO and higher outstanding principal balances associated with our previous credit facilities.
Income Tax Expense. Income tax expense increased by approximately $0.5 million, to $0.6 million for the year ended December 31, 2014 as compared to $0.1 million for the year ended December 31, 2013. Income tax expense is primarily related to the Texas Margin tax, and the increase was primarily due the increase in taxable income between the two periods.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

The following table presents selected financial data for each of the years ended December 31, 2013 and 2012.

In Thousands	Years ended December 31,			
	2013	2012	Change	% Change
REVENUES:				
Natural gas, NGLs and condensate revenue	15,792	34,708	(18,916)	(54.5)%
Gathering, processing, transloading and other revenue	37,068	16,341	20,727	126.8 %
Total Revenues	52,860	51,049	1,811	3.5 %
OPERATING EXPENSES:				
Cost of natural gas, NGLs and condensate revenue	13,999	21,023	(7,024)	(33.4)%
Operation and maintenance	15,891	15,828	63	0.4 %
General and administrative	7,886	4,066	3,820	93.9 %
Property tax expense	1,216	893	323	36.2 %
Depreciation expense	8,197	7,689	508	6.6 %
Total operating expenses	47,189	49,499	(2,310)	(4.7)%
Operating income	5,671	1,550	4,121	265.9 %
Interest expense, net of amounts capitalized	(4,349)	(4,927)	578	(11.7)%
Interest and other income	—	23	(23)	(100.0)%
Loss on interest rate swap	(48)	(851)	803	(94.4)%
Net income (loss) before tax	1,274	(4,205)	5,479	(130.3)%
Income tax expense	88	101	(13)	(12.9)%
Net income (loss)	1,186	(4,306)	5,492	(127.5)%
Key performance metrics:				
Gross margin (1)	38,861	30,026	8,835	29.4 %
Adjusted EBITDA (1)	16,880	9,239	7,641	82.7 %
Volumes:				
Processing Facilities (MMcf/d) (2)	219			
Transloading Facilities (Bbls/d) (2)	18,980			

(1) Gross Margin and Adjusted EBITDA are non-GAAP financial measures. For additional information and a reconciliation of these measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations-How We Evaluate Our Operations."

(2) Volumes reflect the minimum volume commitment under our fee-based contracts or actual throughput, whichever is greater, for the post-IPO period.

Revenues. Natural gas, NGLs and condensate revenue decreased by $18.9 million, or 55%, to $15.8 million for the year ended December 31, 2013 from $34.7 million for the year ended December 31, 2012. The decrease in natural gas, NGLs and condensate revenue is primarily due to the shift in business strategy to fee-based contracts following our IPO, declining NGL prices and a decrease in NGL volumes sold from our Panola County processing facilities. The average price of ethane decreased by 35% to $0.26 per gallon for the year ended December 31, 2013 from $0.40 per gallon for the year ended December 31, 2012. Similarly, the average price per gallon of isobutane and normal butane decreased by 21% and 16% respectively, for the year ended December 31, 2013 as compared to the year ended December 31, 2012. Declining NGL prices attributed to a $7.1 million decrease in our NGL sales for the year ended December 31, 2013 as compared to the year ended December 31, 2012.

We entered into an additional commercial agreement with Anadarko at our Panola County processing facilities, effective August 1, 2012. Under this agreement, Anadarko receives the NGLs extracted on an in-kind basis. We do not sell the NGLs extracted under this agreement, and therefore the NGLs recovered under this agreement are not included in our natural gas, NGLs and condensate sales. As a result, although the number of barrels of NGLs that we recovered increased by 9% for the year ended December 31, 2013 as compared to the year ended December 31, 2012, the number of barrels of NGLs that we sold decreased by 52% for the year ended December 31, 2013 as compared to the year ended December 31, 2012. This decrease was partially offset by an increase in condensate volumes and other NGLs sold under third-party purchase contracts. These changes resulted in a total net decrease of $11.8 million in natural gas, NGLs and condensate revenue for the year ended December 31, 2013 as compared to the year ended December 31, 2012. Gathering, processing, transloading and other revenue increased by $20.7 million for the year ended December 31, 2013 as compared to the year ended December 31, 2012, primarily from our minimum volume commitment agreements with Anadarko and AES. Minimum volume commitment agreements for our gathering and processing segment account for an increase of approximately $14.9 million in fee-based revenue. We expect the trend of increased volumes under fee-based agreements to continue, consistent with our overall business strategy. Our logistics assets became operational in 2013. As such, there are no results of operations or assets related to this segment for the year ended December 31, 2012. For the year ended December 31, 2013, the crude oil logistics segment generated revenues of approximately $5.8 million related directly to our fee-based logistics contracts.

Cost of Revenues. Cost of revenues are derived primarily from the creation of natural gas, NGLs and condensate revenue. Total cost of natural gas, NGLs and condensate revenue decreased by $7.0 million, or 33%, to $14.0 million for the year ended December 31, 2013 as compared to $21.0 million for the year ended December 31, 2012 primarily due to the volume of redelivered gas at the tailgate of our plant in addition to a decline in prices for NGLs. The volume of gas redelivered or sold at the tailgates of our processing facilities is lower than the volume received or purchased at delivery points on our gathering systems or interconnecting pipelines due to the NGLs extracted when the natural gas is processed. Under the keep-whole agreements that were in place during 2012, we were required to make up or “keep the producer whole” for the condensate and NGL volumes extracted from the natural gas stream through the delivery of or payment for a thermally equivalent volume of residue gas. Under certain keep-whole agreements, we purchased natural gas from an affiliate of NuDevco in order to make up or “keep the producer whole” for the condensate and NGL volumes extracted from the natural gas stream during processing. The cost of these “replacement” natural gas volumes was recorded in our cost of natural gas, NGLs and condensate revenue. Under our fee-based agreements, we do not bear the cost of these “replacement” volumes. Furthermore, on July 31, 2013, we assigned all of our keep-whole agreements to AES. The cost of natural gas, NGLs and condensate revenue from affiliates recorded for the year ended December 31, 2013 includes the purchase of $2.5 million of NGLs under our gathering and processing agreement with AES.

Operation and Maintenance Expense. Operation and maintenance expense increased by $0.1 million, or 0.4%, for the year ended December 31, 2013 as compared to the year ended December 31, 2012 primarily due to equity-based compensation expense of $0.9 million and $0.6 million in operating expenses for our logistics contracts. These increases were offset by a decrease in maintenance and operational expenses for our midstream natural gas segment of $1.4 million. Operation and maintenance expenses are primarily composed of expenses related to labor, utilities and chemicals, property insurance premiums, compression costs and maintenance and repair expenses, which generally remain relatively stable across broad ranges of throughput volumes but can fluctuate from period to period depending on the mix of activities performed during the period and the timing of these expenses.

General and Administrative Expense. General and administrative expense increased by approximately $3.8 million, or 94%, to $7.9 million for the year ended December 31, 2013 as compared to $4.1 million for the year ended December 31, 2012. The increase is primarily due to increased audit costs and other professional fees associated with being a publicly traded partnership. Additionally, approximately $2.2 million of equity-based compensation expense from affiliates was recorded to general and administrative expense, for which no such costs were incurred in 2012.

Interest Expense. Interest expense, net of amounts capitalized, decreased by approximately $0.6 million or 12%, to $4.3 million for the year ended December 31, 2013 as compared to $4.9 million for the year ended December 31, 2012. Interest expense increased due to expensing capitalized loan costs associated with our previous credit facilities of $0.8 million for the year ended December 31, 2013 and $0.2 million for the year ended December 31, 2012. This increase was offset against a lower outstanding average principal balance which contributed to a decrease of $1.2 million for interest incurred on our credit facilities during the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Loss on Interest Rate Swap. Loss on interest rate swap decreased by $0.8 million, or 94%, to less than $0.1 million for the year ended December 31, 2013 as compared to $0.9 million for the year ended December 31, 2012. The decrease is primarily due to smaller movements in the interest rate market during 2013. The interest rate swap was settled on July 31, 2013 in connection with the IPO.

LIQUIDITY AND CAPITAL RESOURCES

We closely manage our liquidity and capital resources. The key variables we use to manage our liquidity requirements include our discretionary operation and maintenance expense, general and administrative expense, capital expenditures, credit facility capacity and availability, working capital levels, and the level of investments required to support our growth strategies.

Historically, sources of liquidity included cash generated from operations, equity investments by our sole member and borrowings under our historical credit facility prior to the IPO.

We expect ongoing sources of liquidity to include cash generated from operations, our new revolving credit facility and issuances of additional debt and equity securities. We believe that cash generated from these sources will be sufficient to sustain operations, to finance anticipated expansion plans and growth initiatives, and to make quarterly cash distributions on all of our outstanding units at least at the minimum quarterly distribution rate of $0.35 per unit per quarter. However, in the event our liquidity is insufficient, we may be required to limit our spending on future growth plans or other business opportunities or to rely on external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our growth.

We intend to pay at least the minimum quarterly distribution of $0.35 per unit per quarter, which equates to $6.3 million per quarter, or approximately $25.2 million per year. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no obligation to make quarterly cash distributions in this or any other amounts and our general partner has considerable discretion to determine the amount of our available cash each quarter.

Credit Facility

On February 27, 2015, we entered into a Credit Agreement with Wells Fargo Bank, National Association, as administrative agent, and the lender and agent parties thereto (the “Credit Agreement”) whereby the lenders agreed to extend to us a senior secured revolving credit facility of up to $250 million. Proceeds from the credit facility were used on the closing date for the repayment and termination of our then-existing credit facility and otherwise in connection with the Transactions, and future drawings will be used for working capital, permitted acquisitions and capital expenditures, quarterly distributions of available cash and other general corporate purposes. The maturity date of the Credit Agreement is February 27, 2018.

The Credit Agreement requires that (a) all domestic restricted subsidiaries guarantee our obligations and the obligations of the subsidiary guarantors under (i) the Credit Agreement and other loan documents and (ii) certain hedging agreements and cash management agreements with lenders and affiliates of lenders, and (b) all such obligations be secured by a security interest in substantially all of our assets and the assets of our subsidiary guarantors, in each case, subject to certain customary exceptions. The Credit Agreement provides for a $15 million sublimit for letters of credit and a $15 million sublimit for swingline loans. Borrowings under the Credit Agreement bear interest at (a) the LIBOR Rate (as defined in the Credit Agreement) plus an applicable margin of 2.75% to 3.75% or (b) the Base Rate (as defined in the Credit Agreement) plus an applicable margin of 1.75% to 2.75%, in each case, based on the Consolidated Total Leverage Ratio (as defined in the Credit Agreement). Until such time as we receive gross cash proceeds of not less than $50 million from the consummation of a single issuance of common equity and prepay the loans under the Credit Agreement in an amount not less than $50 million (the “Availability Period”), the amount we may borrow under the Credit Agreement is limited to an amount (the “Availability”) equal to the sum of (a) the product of (i) 4.5 and (ii) Eligible Gas Gathering EBITDA (as defined in the Credit Agreement); plus (b) the lesser of (i) $15 million and (ii) Eligible Transloading EBITDA (as defined in the Credit Agreement). During the Availability Period, the Availability shall be determined periodically in connection with our delivery of annual and quarterly financial statements pursuant to the Credit Agreement and upon the occurrence of certain other events described in the Credit Agreement.

The Credit Agreement contains affirmative and negative covenants customary for credit facilities of its size and nature that, among other things, limit or restrict our ability and the ability of our subsidiaries to (a) incur additional debt; (b) grant certain liens; (c) make certain investments; (d) engage in certain mergers or consolidations; (e) dispose of certain assets; (f) enter into certain types of transactions with affiliates; (g) make distributions, with certain exceptions, including the distribution of Available Cash (as defined in the partnership agreement) if no default or event of default exists and, during the Availability Period, if an Availability deficiency exists, the aggregate amount of distributions of Available Cash made during such deficiency shall not exceed $10 million; (h) enter into certain restrictive agreements or amend certain material agreements and (i) prepay certain debt.

The Credit Agreement requires that our ratio of Consolidated Funded Indebtedness (as defined in the Credit Agreement) on the date of determination to Adjusted Consolidated EBITDA (as defined in the Credit Agreement) for a trailing four fiscal quarter period not exceed 4.50 to 1.00 (or 5.00 to 1.00 for the period commencing on the date that a certain acquisition is consummated through the last day of the second full fiscal quarter following the date of such acquisition). In addition, the Credit Agreement requires our ratio of Adjusted Consolidated EBITDA for a trailing four fiscal quarter period to Consolidated

Interest Expense (as defined in the Credit Agreement) for such period to be at least 2.50 to 1.00. As of February 27, 2015, we had outstanding borrowings of $180.8 million.

CASH FLOWS

Net Cash Flows for the Years Ending December 31, 2014 and 2013

Net cash flows provided by (used in) operating activities, investing activities and financing activities for the year ended December 31, 2014 and 2013 were as follows:

In Thousands	Year Ended December 31, 2014	2013	Change
Net cash provided by (used in):			
Operating activities	$33,264	$9,176	$24,088
Investing activities	$(9,508)	$(12,710)	$3,202
Financing activities	$(24,310)	$1,136	$(25,446)

Operating Activities

Cash flows provided by operating activities increased by $24.1 million to $33.3 million for the year ended December 31, 2014 from $9.2 million for the year ended December 31, 2013. The increase was primarily related to the increase in net income between the periods and the cash outflows in 2013 related to payments made affiliates to reimburse them for costs incurred in the normal course of business prior to our initial public offering.

Investing Activities

Cash flows used in investing activities decreased by $3.2 million to $9.5 million for the year ended December 31, 2014 as compared to $12.7 million for the year ended December 31, 2013, due to a decrease purchases of property, plant and equipment. Cash paid for capital expenditures during the year ended December 31, 2014 primarily included payments for the construction of a one mile pipeline and inlet header system to fully segregate the inlet gas between our Panola 1 and Panola 2 processing facilities. Cash paid for capital expenditures during the year ended December 31, 2013 primarily included payments made to construct the Oak Hill Lateral gathering line and install molecular sieves at our Panola 1 processing facility.

Financing Activities

Cash flows used in financing activities were $24.3 million for the year ended December 31, 2014. Cash flows provided by financing activities were $1.1 million for the year ended December 31, 2013. Cash flows used in financing activities in 2014 were primarily driven by $25.8 million in distributions and $5.5 million of excess purchase price over asset acquired from affiliate, partially offset by $7.0 million of net borrowings from our new revolving credit facility. Cash flows provided by financing activities in 2013 were primarily driven by net proceeds from the IPO of $125.3 million, borrowings under our revolving credit facility of $27.5 million, borrowings from our previous credit facility of $9.0 million and capital contribution of $3.6 million prior to the IPO, partially offset by debt repayments of $23.5 million on our new revolving credit facility, $135.5 million on our previous credit facility.

Net Cash Flows for the Years Ending December 31, 2013 and 2012

Net cash flows provided by (used in) operating activities, investing activities and financing activities for the year ended December 31, 2013 and 2012 were as follows:

In Thousands	Year Ended December 31, 2013	2012	Change
Net cash provided by (used in):			
Operating activities	$9,176	$11,214	$(2,038)
Investing activities	$(12,710)	$(12,445)	$(265)
Financing activities	$1,136	$6,355	$(5,219)

Operating Activities

Cash flows provided by operating activities decreased by $2.0 million to $9.2 million for the year ended December 31, 2013 from $11.2 million for the year ended December 31, 2012. The decrease is primarily related to payments made to reimburse affiliates for costs incurred in the normal course of business prior to our initial public offering, which was partially offset by decreased losses incurred on our derivatives, the addition of our long-term incentive plan current liability of $3.0 million and long-term liability of $32,000 and an increase in net income for the year ended December 31, 2013 as compared to December 31, 2012.

Investing Activities

Cash flows used in investing activities increased by $0.3 million to $12.7 million for the year ended December 31, 2013 as compared to $12.4 million for the year ended December 31, 2012. Cash paid for capital expenditures during the year ended December 31, 2013 primarily included payments made to construct the Oak Hill Lateral gathering line and install molecular sieves at our Panola 1 processing facility. Cash paid for capital expenditures during the year ended December 31, 2012 included payments for the amounts accrued as of December 31, 2011 for the Panola 2 processing plant, as well as commissioning activities incurred early in the twelve months ending December 31, 2012. We also began construction on our Oak Hill Lateral gathering line in the spring of 2012.

Financing Activities

Cash flows from financing activities in historical periods primarily were driven by borrowing under our previous credit facility and capital contributions from our sole member. We used these borrowings and capital contributions to fund our working capital needs and to finance maintenance and expansion capital expenditure projects that are reflected in cash flows used in investing activities.

Cash flows provided by financing activities decreased by $5.2 million to $1.1 million for the year ended December 31, 2013 from $6.4 million for the year ended December 31, 2012. The decrease in 2013 is primarily related to borrowings under our new revolving credit facility of $27.5 million and our previous credit facility of $9.0 million and net proceeds from the IPO of $125.3 million, net against debt repayments of $23.5 million on our revolving credit facility and $135.5 million on our previous credit facility, and a capital contribution of $3.6 million prior to the IPO. During the year ended December 31, 2012, we repaid outstanding indebtedness in the amount of $123.5 million, had borrowings under our previous credit facility of $126.5 million and received capital contributions of $4.3 million.

CAPITAL EXPENDITURES

Our operations require investments to expand, upgrade or enhance existing operations and to meet environmental and operational regulations. Our capital requirements have consisted of maintenance capital expenditures and expansion capital expenditures. Maintenance capital expenditures are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity. Expansion capital expenditures include expenditures to acquire assets and expand existing facilities that increase throughput capacity on our pipelines, processing plants and crude oil logistics assets. Based on current market conditions, we expect to be able to fund our activities for 2015 with cash flows generated from our operations, available cash on hand and borrowings under our Credit Facility as well as accessing the capital markets for debt and equity capital.

Although historically we did not necessarily distinguish between maintenance capital expenditures and expansion capital expenditures in the same manner that we are required to under our partnership agreement subsequent to July 31, 2013, for the years ended December 31, 2014, 2013 and 2012, we estimate that we incurred a total of $1.4 million, $2.3 million and $2.0 million, respectively, for maintenance capital expenditures and incurred a total of $7.1 million, $11.0 million and $9.0 million, respectively, for expansion capital expenditures. Subsequent to the IPO from July 31, 2013 to December 31, 2013, we incurred $0.8 million of maintenance capital expenditures.

During the year ended December 31, 2014, the $7.1 million in expansion capital expenditures primarily related to the construction of a pipeline and inlet header system to fully segregate the inlet gas between our Panola 1 and Panola 2 processing facilities.

During the year ended December 31, 2013, the $11.0 million in expansion capital expenditures primarily related to the construction of our Oak Hill Lateral gathering line and the installation of molecular sieves at our Panola 1 processing facility.

During the year ended December 31, 2012, the $9.0 million in expansion capital expenditures primarily related to our Panola 2 processing plant, which was placed into service in 2011 and became fully operational in May 2012. In 2012, we also began construction on our Oak Hill Lateral.

OFF-BALANCE SHEET ARRANGEMENTS

We do not have any material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

CONTRACTUAL OBLIGATIONS

A summary of our contractual obligations as of December 31, 2014 is as follows:

In Thousands	2015	2016	2017	2018	Thereafter	Total
Operating services agreements (1)	$530	$478	$224	$120	$830	$2,182
Long-term debt (2)	—	—	11,000	—	—	11,000
Total	$530	$478	$11,224	$120	$830	$13,182

(1) Amounts relate to minimum payments for operating services agreements having initial or remaining non-cancellable lease terms in excess of one year, primarily relating to our crude oil logistics facilities.

(2) We had outstanding borrowings of $11.0 million under our revolving credit facility at December 31, 2014 (see Note 6 "Long-Term Debt and Interest Expense"). On February 27, 2015, we entered into the Credit Facility and we repaid all outstanding borrowings under the revolving credit facility. The table above does not include our obligation for the Credit Facility, which has a maturity date of February 27, 2018.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

As of December 31, 2014, there have been no significant changes to our critical accounting policies and estimates disclosed in our Prospectus. We have added a critical accounting policy and estimate with respect to the accounting for our long-term incentive plan awards.

The preparation of consolidated financial statements in accordance with GAAP requires our management to make informed judgments and estimates that affect the amounts of assets and liabilities as of the date of the financial statements and affect the amounts of revenues and expenses recognized during the periods reported. On an ongoing basis, management reviews its estimates, including those related to the determination of properties and equipment, asset retirement obligations, litigation, environmental liabilities, income taxes and fair values. Although these estimates are based on management’s best available knowledge of current and expected future events, changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment and discusses the selection and development of these estimates with the audit committee of our general partner. For additional information relating to our accounting policies, please see Note 2—"Basis of Presentation and Accounting Policies" — to our consolidated financial statements included in Item 8 of this Form 10-K.

Our Revenue Recognition Policies and Use of Estimates for Revenues and Expenses

In general, we recognize revenue from customers when all of the following criteria are met:

- persuasive evidence of an exchange arrangement exists;
- delivery has occurred or services have been rendered;
- the price is fixed or determinable; and

• collectability is reasonably assured.
We record revenue for natural gas and NGL sales and transportation services over the period in which they are earned (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed). While we make every effort to record actual volume and price data, there may be times where we need to make use of estimates for certain revenues and expenses. If the assumptions underlying our estimates prove to be substantially incorrect, it could result in material adjustments in results of operations in future periods.
Depreciation Methods and Estimated Useful Lives of Property, Plant and Equipment
We calculate depreciation expense using the straight-line method over the estimated useful lives of our property, plant and equipment. We assign asset lives based on reasonable estimates when an asset is placed into service. We periodically evaluate the estimated useful lives of our property, plant and equipment and revise our estimates when and as appropriate. Because of the expected long useful lives of the property, plant and equipment, we depreciate our property, plant and equipment over periods ranging from 5 years to 40 years. Changes in the estimated useful lives of the property, plant and equipment could have a material adverse effect on our results of operations.
Impairment of Long-Lived Assets
We review property, plant and equipment and other long-lived assets for impairment whenever events or changes in business circumstances indicate the net book values of the assets may not be recoverable. Impairment is indicated when the undiscounted cash flows estimated to be generated by those assets are less than the assets' net book value. If this occurs, an impairment loss is recognized for the difference between the fair value and net book value. Factors that indicate potential impairment include: a significant decrease in the market value of the asset, operating or cash flow losses associated with the use of the asset, and a significant change in the asset's physical condition or use. No impairments of long-lived assets were recorded during the periods included in these financial statements.
Contingencies
In the ordinary course of business, we may become party to lawsuits, administrative proceedings and governmental investigations, including environmental, regulatory and other matters. As of December 31, 2014 and 2013, we did not have any material outstanding lawsuits, administrative proceedings or governmental investigations.
Accounting for Derivative and Hedging Activities
From time to time, we may enter into derivative transactions to mitigate our exposure to price fluctuations in NGLs and utilize derivative instruments to manage our exposure to interest rate risk. We recognize all derivative instruments as either assets or liabilities in our consolidated and combined Balance Sheets at their respective fair value. For derivatives designated in hedging relationships, changes in the fair value are recognized in accumulated other comprehensive income, to the extent the derivative is effective at offsetting the changes in cash flows being hedged, until the hedged item affects earnings.
We formally assess, both at the inception of the hedging transaction and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged transactions. For derivative instruments that are designated and qualify as part of a cash flow hedging transaction, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.
We discontinue hedge accounting prospectively when we determine that the derivative is no longer effective in offsetting cash flows attributable to the hedged risk, the derivative expires or is sold, terminated, or exercised, the cash flow hedge is de-designated because a forecasted transaction is not probable of occurring, or management determines to remove the designation of the cash flow hedge.
In all situations in which hedge accounting is discontinued and the derivative remains outstanding, we continue to carry the derivative at its fair value on the balance sheet and recognize any subsequent changes in its fair value in earnings. When it is probable that a forecasted transaction will not occur, we discontinue hedge accounting and recognize immediately in earnings gains and losses that were accumulated in other comprehensive income related to the hedging relationship.
Our commodity derivative instruments are recorded at fair value using broker quoted market prices of similar contracts. Our interest rate swap derivatives are valued using current forward interest rates as quoted by brokers to be received in the cash market.

Accounting for Awards under the Long-term Incentive Plan

In connection with the IPO, the board of directors of our general partner adopted the Marlin Midstream Partners, LP 2013 Long-Term Incentive Plan (LTIP). Individuals who are eligible to receive awards under the LTIP include (1) our employees and the employees of NuDevco Midstream Development and its affiliates, (2) directors of the Partnership's general partner, and (3) consultants. The LTIP provides for the grant of unit options, unit appreciation awards, restricted units, phantom units, distribution equivalent rights, unit awards, profits interest units, and other unit-based awards. The maximum number of common units issuable under the LTIP is 1,750,000.

All of the phantom unit awards granted to-date are considered non-employee equity based awards and are required to be remeasured at fair market value at each reporting period and amortized to compensation expense on a straight-line basis over the vesting period of the phantom units with a corresponding increase in a liability. We intend to settle the awards by allowing the recipient to choose between issuing the net amount of common units due, less common units equivalent to pay withholding taxes, due upon vesting with the Partnership paying the amount of withholding taxes due in cash or issuing the gross amount of common units due with the recipient paying the withholding taxes. The phantom unit awards were awarded to individuals who are not deemed to be employees of the Partnership.

Distribution equivalent rights are accrued for each phantom unit award as the Partnership declares cash distributions and are recorded as a decrease in partners' capital with a corresponding liability in accordance with the vesting period of the underlying phantom unit, which will be settled in cash when the underlying phantom units vest.

As a result of the Transactions, the awards previously issued under the LTIP immediately vested due to the change in control of our general partner. Azure, as general partner, plans to continue to operate under the LTIP in the future. However, there were no awards issued under the LTIP in connection with or immediately following the closing of the Transactions, and Azure, as general partner, has the ability to determine the terms and conditions of the awards issued under the LTIP, which may differ from those previously issued.

NEW ACCOUNTING STANDARDS

In May 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014-09 will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective on January 1, 2017. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. We are evaluating the effect that ASU 2014-09 will have on our consolidated financial statements and related disclosures. We have not yet selected a transition method nor have we determined the effect of the standard on our ongoing financial reporting.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Interest Rate Risk

We had exposure to changes in interest rates on our indebtedness associated with our historical credit facility described above in Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities." We entered into an interest rate swap contract, effective December 17, 2012, with a notional amount that declines over time. The contract effectively limited our LIBOR based interest rate exposure related to the notional amount of the swap contract through December 17, 2014. At the closing of the IPO, the interest rate swap was terminated and settled for approximately $0.1 million.

We have exposure to changes in interest rates under our new revolving credit facility. The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A 10% change in interest rates would not have had a material impact on our operating income, financial condition or cash flows as of December 31, 2014.

Commodity Price Risk

With the execution of a fee-based gathering and processing agreement and multiple fee-based transloading services agreements with AES at the closing of the IPO, substantially all of our gross margin are generated under fee-based commercial agreements, the substantial majority of which have minimum volume commitments. We believe these commercial arrangements promote stable cash flows and minimal direct commodity price exposure. Accordingly, we have not entered into any derivative contracts to manage our exposure to commodity price risk, and, as a result of our limited exposure to commodity price risk under our fee-based commercial agreements, we do not plan to enter into hedging arrangements to manage such risk subsequent to the closing of the IPO. Natural gas and NGL prices can affect our profitability indirectly by influencing the level of drilling and production activity by our producer customers, the willingness of our non-producer customers to purchase natural gas for processing and the volumes of natural gas delivered to us for processing by all of our customers.

A 10% change in commodity prices would not have had a material impact on our operating income, financial condition or cash flows as of December 31, 2014.

Counterparty and Customer Credit Risk

For the year ended December 31, 2014, AES and Anadarko each accounted for more than 10% of our revenues. Although we have gathering and processing agreements with Anadarko, and these agreements have remaining terms ranging from one to five years. In addition, at the closing of the IPO, we entered into a three-year fee-based gathering and processing agreement with AES at our Panola County processing facilities. Under this agreement, AES pays us a fixed fee per Mcf (subject to an annual inflation adjustment) for gathering, treating, compression and processing services and a per gallon fixed fee for NGL transportation services. As these contracts expire, we will have to renegotiate extensions or renewals with these customers or replace the existing contracts with new arrangements with other customers. If any of these customers were to default on its contracts or if we were unable to renew our contracts with them on favorable terms, we may not be able to replace such customers in a timely fashion, on favorable terms or at all. In any of these situations, our revenues and cash flows and our ability to make cash distributions to our unitholders would be materially and adversely affected.

In addition, AES is our sole customer with respect to our crude oil logistics business, and we expect to continue to derive the substantial majority of our transloading revenues from AES. At the closing of the IPO, AES contracted for 100% of the capacity at our Wildcat, Big Horn, and Eastern New Mexico facilities. Such concentration subjects us to increased risk in the case of nonpayment, nonperformance or non-renewal by AES under the transloading services agreements that we entered into with AES at the closing of the IPO. Any adverse developments concerning AES could materially and adversely affect our crude oil logistics business. On February 27, 2015, we entered into amendments to our Wildcat, Big Horn and Ladder transloading service agreements that extended the maturity to February 27, 2020.

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Item 8. Financial Statements and Supplementary Data

MARLIN MIDSTREAM PARTNERS, LP

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors of Marlin Midstream GP, LLC
and
The Unitholders of Marlin Midstream Partners, LP
and
The General Partner of Marlin Midstream Partners, LP:

We have audited the accompanying consolidated balance sheets of Marlin Midstream Partners, LP and subsidiaries (the Partnership) as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations and comprehensive income (loss), partners' capital and member's equity, and cash flows for each of the years in the three-year period ended December 31, 2014. These consolidated and combined financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits.

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

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of Marlin Midstream Partners, LP and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP
Houston, Texas
March 11, 2015

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements

MARLIN MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(in thousands, except unit amounts)

	December 31, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$2,603	$3,157
Accounts receivable	1,545	2,969
Accounts receivable—affiliates	3,963	3,632
Inventory	213	321
Prepaid assets	456	330
Other current assets	285	285
Total current assets	9,065	10,694
PROPERTY, PLANT AND EQUIPMENT, NET	162,158	162,548
OTHER ASSETS	615	900
TOTAL ASSETS	$171,838	$174,142
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$1,185	$2,791
Accrued liabilities	2,370	2,131
Accounts payable—affiliates	1,438	1,552
Long-term incentive plan payable - affiliates	547	2,752
Total current liabilities	5,540	9,226
LONG-TERM LIABILITIES		
Long-term incentive plan payable - affiliates	469	291
Deferred income tax	399	75
Long-term debt	11,000	4,000
Total liabilities	17,408	13,592
PARTNERS' CAPITAL		
Common units (8,979,248 and 8,724,545 issued and outstanding at December 31, 2014 and 2013, respectively)	141,156	142,587
Subordinated units (8,724,545 issued and outstanding at December 31, 2014 and 2013)	12,714	17,258
General partner units (357,935 and 356,104 issued and outstanding at December 31, 2014 and 2013, respectively)	560	705
Total partners' capital	154,430	160,550
TOTAL LIABILITIES AND PARTNERS' CAPITAL	$171,838	$174,142

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

MARLIN MIDSTREAM PARTNERS, LP
CONSOLIDATED AND COMBINED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
(in thousands, except per unit amounts)

	For the year ending December 31,		
	2014	2013	2012
REVENUES:			
Natural gas, NGLs and condensate revenue	$13,569	$15,792	$34,708
Gathering, processing, transloading and other revenue	23,635	24,053	16,087
Gathering, processing, transloading and other revenue—affiliates	38,024	13,015	254
Total Revenues	75,228	52,860	51,049
OPERATING EXPENSES:			
Cost of natural gas, NGLs and condensate revenue	4,790	8,484	13,355
Cost of natural gas, NGLs and condensate revenue—affiliates	12,558	5,515	7,668
Operation and maintenance	8,899	12,401	15,035
Operation and maintenance—affiliates	6,668	3,490	793
General and administrative	3,602	3,699	3,045
General and administrative—affiliates	5,067	4,187	1,021
Property tax expense	1,316	1,216	893
Depreciation expense	8,817	8,197	7,689
Loss on disposals of equipment	60	—	—
Total operating expenses	51,777	47,189	49,499
Operating income	23,451	5,671	1,550
Interest expense, net of amounts capitalized	(766)	(4,349)	(4,927)
Interest and other income	—	—	23
Loss on interest rate swap	—	(48)	(851)
Net income (loss) before tax	22,685	1,274	(4,205)
Income tax expense	553	88	101
Net income (loss)	22,132	1,186	(4,306)
Other comprehensive income (loss)			
Deferred gain from cash flow hedges	—	—	689
Reclassification of deferred gain from cash flow hedges into net income	—	—	(752)
Comprehensive income (loss)	$22,132	$1,186	$(4,369)
Net income (1)	$22,132	$7,190	
Less: Allocation of East New Mexico Dropdown net income prior to acquisition (see Note 5)	(160)	—	
Less: general partner interest in net income	(435)	(144)	
Limited partner interest in net income	$21,537	$7,046	
Net income per limited partner common unit - basic	$1.23	$0.40	
Net income per limited subordinated unit - basic	$1.22	$0.40	
Net income per limited partner common unit - diluted	$1.21	$0.39	
Net income per limited subordinated unit - diluted	$1.22	$0.40	

(1) Post-IPO, August 1, 2013 to December 31, 2013 for the year ended December 31, 2013.

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

MARLIN MIDSTREAM PARTNERS, LP
CONSOLIDATED AND COMBINED STATEMENT OF PARTNERS' CAPITAL AND MEMBER'S EQUITY
(in thousands)

	Member's Equity	General Partner Units	Subordinated Units	Common Units	Total
Balance at December 31, 2011	32,274	—	—	—	32,274
Net loss	(4,306)	—	—	—	(4,306)
Capital contributions	4,374	—	—	—	4,374
Deferred gain from cash flow hedges	689	—	—	—	689
Reclassification of deferred gain from cash flow hedges	(752)	—	—	—	(752)
Balance at December 31, 2012	32,279	—	—	—	32,279
Net loss attributable to the period from January 1, 2013 through July 31, 2013	(6,003)	—	—	—	(6,003)
Capital contributions through July 31, 2013	3,574	—	—	—	3,574
Transfer of net liabilities to NuDevco Midstream Development, LLC on July 31, 2013	2,307	—	—	—	2,307
Contribution of net assets to Marlin Midstream Partners, LP at July 31, 2013	(32,157)	643	15,757	15,757	—
Issuance of common units from Initial Public Offering, net of underwriting discount and other direct IPO costs at July 31, 2013	—	—	—	125,329	125,329
Distributions through December 31, 2013	—	(82)	(2,022)	(2,022)	(4,126)
Net income attributable to the period from August 1, 2013 through December 31, 2013	—	144	3,523	3,523	7,190
Balance at December 31, 2013	—	705	17,258	142,587	160,550
Issuance of common units under the Long-Term Incentive Plan	—	—	—	2,962	2,962
Net income	—	435	10,614	10,923	21,972
Distributions	—	(509)	(12,473)	(12,837)	(25,819)
Issuance of general partner units (Note5)	—	38	—	—	38
Issuance of common units for assets acquired from affiliate (Note5)	—	—	—	257	257
Excess cash purchase price over historical cost of assets acquired from affiliate (Note 5)	—	(109)	(2,685)	(2,736)	(5,530)
Balance at December 31, 2014	—	560	12,714	141,156	154,430

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

MARLIN MIDSTREAM PARTNERS, LP
CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31, 2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$22,132	$1,186	$(4,306)
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Loss on disposal	60	—	—
Allocation of East New Mexico Dropdown net income prior to acquisition	(160)	—	—
Depreciation expense	8,817	8,197	7,689
Amortization of deferred financing costs	285	1,269	542
Equity-based compensation	1,963	3,012	—
Deferred income tax	325	75	—
Unrealized gain (loss) on derivatives	—	(57)	(4,196)
Unrealized Gain (loss) on derivatives—affiliates	—	—	(344)
Changes in assets and liabilities:			
(Increase) Decrease in accounts receivable	1,424	3,752	(480)
(Increase) decrease in accounts receivable—affiliates	(332)	(3,526)	1,267
(Increase) decrease in inventory	108	(28)	132
(Increase) decrease in prepaid assets	(126)	(235)	(36)
(Increase) decrease in other current assets	—	3	236
(Increase) decrease in other assets	—	51	(679)
Increase (decrease) in accounts payable	(324)	120	(108)
Increase (decrease) in accrued liabilities	234	813	1,192
Increase in long-term incentive plan payable	(1,028)	32	—
Increase (decrease) in accounts payable—affiliates	(114)	(5,488)	10,305
Net cash provided by operating activities	33,264	9,176	11,214
CASH FLOWS FROM INVESTING ACTIVITIES:			
Purchases of property, plant and equipment	(9,508)	(12,710)	(12,445)
Net cash used in investing activities	(9,508)	(12,710)	(12,445)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Member Capital contributions	—	3,574	4,287
Issuance of general partner units	38	—	—
Borrowing of long-term debt	29,500	36,500	126,500
Repayments on long-term debt	(22,500)	(159,000)	(123,500)
Payment of deferred financing costs	—	(1,141)	(932)
Distributions	(25,818)	(4,126)	—
Proceeds from IPO, net of underwriting discount and other costs	—	125,329	—
Excess cash purchase price over historical cost of assets acquired from affiliate (Note 5)	(5,530)	—	—
Net cash (used in) provided by financing activities	(24,310)	1,136	6,355
NET INCREASE IN CASH AND CASH EQUIVALENTS	(554)	(2,398)	5,124
CASH AND CASH EQUIVALENTS—Beginning of Period	3,157	5,555	431
CASH AND CASH EQUIVALENTS—End of Period	$2,603	$3,157	$5,555
Supplemental Cash Flow Information:			
Cash paid for interest	$510	$3,448	$4,296
Accrual of construction-in-progress and capital expenditures	$125	$1,407	$635

Cash paid for income taxes	$52	$40	$67
Issuance of common units for assets acquired from affiliate (Note 5)	$257	$—	$—
Contribution of property from sole member	$—	$—	$87
Net assets contributed to NuDevco Midstream Development, LLC	$—	$9,385	$—
Intercompany accounts payable assigned to NuDevco Midstream Development, LLC	$—	$11,692	$—

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

MARLIN MIDSTREAM PARTNERS, LP
NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

1. ORGANIZATION
Organization
Marlin Midstream Partners, LP (the "Partnership") is a midstream energy company that offers (i) natural gas gathering, compression, dehydration, treating, processing, and hydrocarbon dew-point control and transportation services to producers, marketers and third-party pipeline companies, and (ii) crude oil transloading services to Associated Energy Services, LP ("AES"), an affiliate of the Partnership.
The Partnership is a Delaware limited partnership, formed in April 2013 by NuDevco Partners, LLC and its affiliates (“NuDevco”). NuDevco, a sole member limited liability company formed on August 27, 2010 under the Texas Limited Liability Company Act (“TLLCA”), is an affiliate of Spark Energy Ventures, LLC (“SEV”), a sole member limited liability company formed on October 8, 2007 under the TLLCA. NuDevco and SEV are both wholly owned by W. Keith Maxwell III. SEV was the sole member of Marlin Midstream, LLC and its subsidiaries ("Marlin Midstream"), and Mr. Maxwell was the sole member of Marlin Logistics, LLC ("Marlin Logistics") prior to the closing of the Partnership's initial public offering of 6,875,000 common units representing a 38.6% limited partner interest in the Partnership on July 31, 2013 ("IPO") as discussed below. Concurrently, with the closing of the IPO, the Partnership also executed a new credit facility as discussed below.
In connection with the closing of the IPO, SEV contributed all of its interest in Marlin Midstream to the Partnership, and Mr. Maxwell contributed all of his interest in Marlin Logistics to the Partnership, through a series of transfers of interest in entities all under the common control of Mr. Maxwell in exchange for wholly owned subsidiaries of NuDevco receiving common units and all of the Partnership’s subordinated units and incentive distribution rights. The contribution of entities, as discussed above, to the Partnership is not considered a business combination accounted for under the purchase method, as it was a transfer of assets and operations under common control and, accordingly, balances were transferred at their historical cost. The Partnership's historical combined financial statements prior to the IPO are prepared using Marlin Midstream's and Marlin Logistics' historical basis in the assets and liabilities, and include all revenues, costs, assets and liabilities attributed to these entities for the periods presented. The Partnership's financial statements subsequent to the IPO are prepared on a consolidated basis.
The Partnership’s general partner, Marlin Midstream GP, LLC manages the Partnership’s activities subject to the terms and conditions specified in the Partnership’s partnership agreement. The Partnership’s general partner is owned by NuDevco Midstream Development, LLC ("NuDevco Midstream Development"), an indirect wholly owned subsidiary of NuDevco. The operations of the general partner, in its capacity as general partner, are managed by its board of directors. Actions by the general partner that are made in its individual capacity will be made by NuDevco Midstream Development as the sole member of the Partnership's general partner and not by the board of directors of the general partner. The partnership's general partner will not be elected by the Partnership's unitholders and will not be subject to re-election on a regular basis in the future. The officers of the general partner will manage the day-to-day affairs of the Partnership's business.
Marlin Midstream was formed November 26, 2002 as a sole member limited liability company under the TLLCA. Marlin Midstream is a midstream energy company offering the following midstream services: natural gas gathering, compression, dehydration, treating, processing and hydrocarbon dew-point control and transportation services to producers, third-party pipeline companies and marketers.
Marlin Logistics, formerly known as FuelCo Energy, LLC, was formed August 26, 2010 as a sole member limited liability company under the TLLCA. Marlin Logistics is a crude oil logistics company that offers crude oil transloading services.
As a company with less than $1.0 billion in revenues during its last fiscal year, the Partnership qualifies as an “emerging growth company” as defined in the Jumpstart Our Business Startups Act of 2012, or the JOBS Act. An emerging growth company may take advantage of specified reduced reporting and other regulatory requirements for up to five years that are otherwise applicable generally to public companies.

The Partnership will remain an emerging growth company for five years unless, prior to that time, annual revenues total more than $1.0 billion, the Partnership becomes a “large accelerated filer,” as defined in Rule 12b-2 promulgated under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), or the Partnership issues more than $1.0 billion of non-convertible debt over a three-year period.

As a result of our election to avail ourselves of certain provisions of the JOBS Act, the information that we provide may be different than what you may receive from other public companies in which you hold an equity interest.

Initial Public Offering of Marlin Midstream Partners, LP

On July 31, 2013, the Partnership completed the IPO of 6,875,000 common units, representing a 38.6% limited partner interest, to the public for $20.00 per common unit, less an underwriting discount of $1.20 per common unit. After the closing of the IPO, substantially all the Partnership's gross margin is generated under fee-based commercial agreements, the substantial majority of which have minimum volume commitments.

The Partnership’s general partner is entitled to 2.0% of all distributions that the Partnership makes. The general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us in order to maintain its 2.0% general partner interest if the Partnership issues additional units. The 2.0% general partner interest, and the percentage of the Partnership’s cash distributions to which the general partner is entitled from such 2.0% interest, will be proportionately reduced if the Partnership issues additional units in the future (other than the issuance of common units upon conversion of outstanding subordinated units or the issuance of common units upon a reset of the incentive distribution rights) and the Partnership’s general partner does not contribute a proportionate amount of capital to the Partnership in order to maintain the general partners 2.0% general partner interest.

NuDevco indirectly holds all of the incentive distribution rights issued in the IPO, which entitles NuDevco to receive an increasing percentage (13.0%, 23.0% and 48.0%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and certain target distribution levels have been achieved. The maximum distribution of 48.0% does not include any distributions that the Partnership’s general partner or its affiliates may receive on common, subordinated or general partner units that they own.

The Partnership’s partnership agreement provides that, during the defined subordination period, the common units have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.35 per common unit before any distributions of available cash from operating surplus may be made on the subordinated units. The subordinated units are deemed “subordinated” because for a defined period of time the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages accrue or are payable on the subordinated units.

Net proceeds to the Partnership from the IPO were $125.3 million, after underwriting discount, structuring fees and other direct IPO costs. Using those proceeds, the Partnership repaid its existing credit facility of approximately $121.9 million and the outstanding revolving credit facility of approximately $10.0 million, and settled its existing interest rate swap liability of approximately $0.1 million.

At the consummation of the IPO, the amount of common, subordinated, and general partner units is summarized in the table below:

	Number of units at July 31, 2013	Limited Partner Interest
Publicly held common units	6,875,000	38.6%
Common units held by NuDevco	1,849,545	10.4%
Subordinated units held by NuDevco	8,724,545	49.0%
General partner units	356,104	2.0%
Total	17,805,194	100.0%

Our Fee-Based Commercial Agreements

Prior to the IPO, the Partnership generated revenues primarily under keep-whole and other commodity-based gathering and processing agreements with third parties and its affiliates. At the closing of the IPO, the Partnership terminated the existing commodity-based gas gathering and processing agreement with AES, assigned to AES all of the remaining keep-whole and other commodity-based gathering and processing agreements with third party customers and entered into a new three-year fee-based gathering and processing agreement with AES with a minimum volume commitment and annual inflation adjustments.

Following the closing of the IPO, the Partnership has multiple fee-based commercial agreements in place with Anadarko Petroleum Corporation (“Anadarko”) and AES, substantially all of which include minimum volume commitments and annual inflation adjustments that will initially be the source of a substantial portion of the Partnership's revenues.

Credit Facility

Concurrently with the closing of the IPO, the Partnership entered into a new $50.0 million senior secured revolving credit facility, which matures on July 31, 2017. If no event of default has occurred, the Partnership has the right, subject to approval by the administrative agent and certain lenders, to increase the borrowing capacity under the revolving credit facility to up to $150.0 million. The new revolving credit facility is available to fund expansions, acquisitions and working capital requirements for operations and general corporate purposes. At the closing of the IPO, the Partnership borrowed $25.0 million under the new revolving credit facility. At December 31, 2014, $11.0 million was outstanding under the new revolving credit facility.

At our election, interest will be generally determined by reference to:

- the Eurodollar rate plus an applicable margin between 3.0% and 3.75% per annum (based upon the prevailing senior secured leverage ratio); or
- the alternate base rate plus an applicable margin between 2.0% and 2.75% per annum (based upon the prevailing senior secured leverage ratio). The alternate base rate is equal to the highest of Société Générale's prime rate, the federal funds rate plus 0.5% per annum or the reference Eurodollar rate plus 1.0%.

Our new revolving credit facility is secured by the capital stock of our present and future subsidiaries, all of our and our subsidiaries' present and future property and assets (real and personal), control agreements relating to our and our subsidiaries' bank accounts and other instruments, investment property, general intangibles and contract rights, including rights under any agreements with AES or Anadarko.

Our new revolving credit facility also contains covenants that, among other things, require us to maintain specified ratios or conditions. We must maintain a consolidated senior secured leverage ratio, consisting of consolidated indebtedness under our new revolving credit facility to consolidated EBITDA of not more than 4.0 to 1.0, as of the last day of each fiscal quarter. In addition, we must maintain a consolidated interest coverage ratio, consisting of our consolidated EBITDA minus capital expenditures to our consolidated interest expense, letter of credit fees and commitment fees of not less than 2.5 to 1.0, as of the last day of each fiscal quarter.

In addition, our new revolving credit facility contains affirmative covenants that are customary for credit facilities of this type. The covenants will include delivery of financial statements and other information (including any filings made with the SEC), maintenance of property and insurance, payment of taxes and obligations, material compliance with laws, inspection of property, books and records and audits, use of proceeds, payments to bank blocked accounts, notice of defaults and certain other customary matters. For additional information relating to our long-term debt, please see Note 6, "Long-Term Debt and Interest Expense," to our Consolidated Financial Statements included in this Form 10-K.

Other Transactions in Connection with the Consummation of the IPO:

On July 31, 2013, in connection with the closing of the IPO, the following transactions occurred:

- the Partnership's general partner maintained its 2.0% general partner interest, and all of the Partnership's incentive distribution rights were issued to Marlin IDR Holdings, LLC;
- the Partnership issued 1,849,545 common units and 8,724,545 subordinated units to NuDevco Midstream Development for the contributions by SEV and Mr. Maxwell, representing a 49.0% limited partner interest in the Partnership;
- the Partnership transferred to affiliates of NuDevco (i) the Partnership's 50% interest in a CO_2 processing facility located in Monell, Wyoming, (ii) certain transloading assets and purchase commitments owned by Marlin Logistics that are not currently under a service contract, (iii) certain property, plant and equipment and other equipment not yet in service and (iv) certain other immaterial contracts;
- NuDevco assumed $11.7 million of the non-current accounts payable balance owed by Marlin Midstream to affiliates of SEV and Marlin Midstream was released from such obligations; and
- the Partnership entered into an omnibus agreement with the general partner and its affiliates that addresses (i) the management and administrative services to be provided by NuDevco to the Partnership and the corresponding fees and expense reimbursements to be paid to NuDevco in connection therewith, (ii) the indemnification obligations between NuDevco and the Partnership for environmental and other liabilities and the operation of assets and (iii) the Partnership's right of first offer on certain of NuDevco Midstream Development's midstream energy assets.

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2. BASIS OF PRESENTATION AND ACCOUNTING POLICIES
The consolidated and combined financial statements have been prepared in accordance with generally accepted accounting principles in the United States ("GAAP") and pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC").
In preparing financial statements in accordance with GAAP, management makes informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, utilizing historical experience and other methods considered reasonable under the particular circumstances. Changes in facts and circumstances or additional information may result in revised estimates and actual results may differ from these estimates. Effects on the business, financial condition and results of operations resulting from revisions to estimates are recognized when the facts that give rise to the revision become known. The information furnished herein reflects all normal recurring adjustments which are, in the opinion of management, necessary for a fair presentation of the consolidated and combined financial statements. The consolidated and combined financial statements include the accounts of the Partnership and its wholly-owned subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation.
The accompanying combined financial statements have been prepared in accordance with Regulation S-X, Article 3, General Instructions as to Financial Statements and Staff Accounting Bulletin ("SAB") Topic 1-B, Allocations of Expenses and Related Disclosures in Financial Statements of Subsidiaries, Divisions or Lesser Business Components of Another Entity. Certain expenses incurred by SEV are only indirectly attributable to Marlin Midstream prior to the IPO. As a result, certain assumptions and estimates are made in order to allocate a reasonable share of such expenses to the Partnership, so that the accompanying combined financial statements reflect substantially all costs of doing business. The allocations and related estimates and assumptions are described more fully in Note 11-"Transactions with Affiliates", which the Partnership believes are reasonable.
SEV has allocated various corporate overhead expenses to the Partnership based on percentage of departmental usage, wages or headcount. These allocations are not necessarily indicative of the cost that the Partnership would have incurred had it operated as an independent stand-alone entity prior to the IPO. As such, the consolidated and combined financial statements do not fully reflect what the Partnership's financial position, results of operations and cash flows would have been had the Partnership operated as a stand-alone company prior to the IPO.
At the closing of the IPO, the Partnership entered into an omnibus agreement with NuDevco and its affiliates which addresses the management and administrative services to be provided by NuDevco to the Partnership and the corresponding fees and expense reimbursements to be paid to NuDevco in connection therewith. Under the omnibus agreement, the Partnership pays an annual fee, currently in the amount of $0.6 million, for executive management services and is allocated general and administrative and operating expenses that are directly attributable to the Partnership.
Prior to the IPO, Marlin Midstream relied upon SEV and its affiliates as a participant in SEV's credit facility. As a result, historical combined financial information prior to the IPO is not necessarily indicative of what the Partnership's results of operations, financial position and cash flows will be in the future.
On August 1, 2014, the Partnership acquired 100% interest in the East New Mexico Transloading Facility ("East New Mexico Dropdown") from NuDevco Midstream Development. As the acquisition represented a transfer of assets under common control, the consolidated financial statements and related information presented herein have been recast to include the historical results of the East New Mexico Dropdown since July 2, 2014, the date the facility commenced operations. See Note 5 (“Property, Plant and Equipment”) for further discussion of the transaction.
Cash and Cash Equivalents
Cash and cash equivalents consist of all unrestricted demand deposits and funds invested in highly liquid instruments with original maturities of three months or less. The Partnership periodically assesses the financial condition of the institutions where these funds are held and believes that its credit risk is minimal.
Accounts Receivable
Trade accounts receivable are recorded at the invoiced amount and do not bear interest. Amounts collected on trade accounts receivable are included in net cash provided by operating activities in the consolidated and combined statements of cash flows. The Partnership does not maintain an allowance for doubtful accounts. The Partnership

elects to use the direct write-off method based on its collection history. For the years ended December 31, 2014 and 2013, no accounts receivable were written off.

Inventory

Inventory consists of NGLs and chemicals in bulk storage and is valued at the lower of weighted average cost or market. NGL inventories are used for sales contract requirements. Chemical inventories are expensed as transferred from bulk storage into production and are recorded in operation and maintenance in the consolidated and combined statements of operations.

Deferred Financing Costs

Costs incurred in connection with the issuance of long-term debt are capitalized and amortized to interest expense using the effective interest method over the life of the related debt.

Property, Plant and Equipment

Property, plant and equipment are stated at cost. Depreciation on property, plant and equipment is recorded on a straight-line basis for groups of property having similar economic characteristics over the estimated useful lives (primarily 5 to 40 years). Uncertainties that may impact these estimates include, but are not limited to, changes in laws and regulations relating to environmental matters, including air and water quality, restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are placed into service, management makes estimates with respect to useful lives. However, subsequent events could cause a change in estimates, thereby impacting future depreciation amounts.

When items of property, plant and equipment are sold or otherwise disposed of, gains or losses are reported in the consolidated and combined statements of operations.

The Partnership capitalizes all construction-related direct labor and material costs, as well as indirect construction costs. Indirect construction costs include general engineering, insurance, taxes and the cost of funds used during construction. Capitalized interest is calculated by multiplying the Partnership’s monthly weighted average interest rate on outstanding debt by the amount of qualifying costs. Capitalized interest cannot exceed monthly gross interest expense. After major construction projects are completed, the associated capitalized costs including interest are depreciated over the estimated useful life of the related asset. During the years ended December 31, 2014 and 2013, respectively, the Partnership recorded $45,000 and $0.2 million of capitalized interest, respectively.

Costs, including complete asset replacements and enhancements or upgrades that increase the original efficiency, productivity or capacity of property, plant and equipment, are also capitalized. In addition, certain of the Partnership’s plant assets require periodic and scheduled maintenance, such as overhauls. The cost of these scheduled maintenance projects are capitalized and depreciated on a straight-line basis until the next planned maintenance, which generally occurs every 5 years.

Costs for planned integrity management projects are expensed in the period incurred. These types of costs include in-line inspection services, contractor repair services, materials and supplies, equipment rentals and labor costs. The costs of repairs, minor replacements and maintenance projects, which do not increase the original efficiency, productivity or capacity of property, plant and equipment, are expensed as incurred.

Impairment of Long-lived Assets

The Partnership evaluates its long-lived assets for impairment whenever events or changes in circumstances indicate the carrying amount of an asset may not be recoverable. A long-lived asset is considered impaired when the sum of the estimated, undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, estimates of future undiscounted cash flows take into account possible outcomes and probabilities of their occurrence. If the carrying amount of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recognized to the extent the carrying value exceeds the estimated fair value of the long-lived asset. With respect to natural gas processing plants and pipelines and NGL pipelines, management considers the volume of third-party reserves behind the asset and future NGL and natural gas prices to estimate cash flows. The amount of additional reserves developed by future drilling activity depends, in part, on expected natural gas prices. Projections of reserves, drilling activity, and future commodity prices are inherently subjective and contingent upon a number of variable factors, many of which are difficult to forecast. Any significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset group.

For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value, less the cost to sell, to determine if impairment is required. Until the assets are disposed of, an estimate of the fair value is determined when related events occur or circumstances change. There were no asset impairments for the years ended December 31, 2014 and 2013.

Segment Reporting

The Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) Topic 280, Segment Reporting, established standards for entities to report information about the operating segments and geographic areas in which they operate. The Partnership operates two segments, gathering and processing and crude oil logistics, and all of its operations are located in the United States. Our crude oil logistics segment had no material assets or operations as of or prior to December 31, 2012.

Revenues and Cost of Revenues

The Partnership’s revenues are derived primarily from natural gas processing and fees earned from its gathering and processing operations. Revenues are recognized by the Partnership using the following criteria: (1) persuasive evidence of an exchange arrangement exists, (2) delivery has occurred or services have been rendered, (3) the buyer’s price is fixed or determinable and collection is reasonably assured. Utilizing these criteria, revenues are recognized when the commodity is delivered or services are rendered. Similarly, cost of revenues is recognized when the commodity is purchased or delivered.

The Partnership’s fee-based contracts provide for a fixed fee arrangement for one or more of the following midstream services: natural gas gathering, compression, dehydration, treating, processing and hydrocarbon dew-point control and transportation services to producers, third- party pipeline companies and marketers. Under these arrangements, the Partnership is paid a fixed fee based on the volume of the natural gas the Partnership gathers and processes, and recognizes revenues for its services in the month such services are performed. Substantially all of these fee-based agreements contain minimum volume commitments and annual inflation adjustments.

Historically, under commercial agreements that did not require us to deliver NGLs to the customer in kind, we provided NGL transportation services to the customer whereby we purchased the NGLs from the customer at an index price, less fractionation and transportation fees, and simultaneously sold the NGLs to third parties at the same index price, less fractionation fees. The revenue generated by these activities was offset by a corresponding cost of revenues that was recorded when we compensated the customer for its share of the NGLs.

Producers’ wells and other third-party gathering systems are connected to the Partnership’s gathering systems for delivery of natural gas to the Partnership’s processing and treating plants, where the natural gas is processed to extract NGLs and condensate or treated in order to satisfy downstream natural gas pipeline specifications. Under percentage of liquids (“POL”) arrangements, the Partnership retained a percentage of the liquids processed. Both the Partnership and producer depended on the volume of the commodity and its value and each party received a percentage of the commodity revenues. Revenues were directly correlated to the commodity’s market value. POL contracts also include fee-based revenues for gathering and other midstream services. Under both fixed fee and POL arrangements, the counterparties’ share of NGLs, if not delivered as a commodity, was recorded as cost of revenues.

Under its keep-whole contracts, the Partnership was required to gather or purchase raw natural gas at current market rates. The volume of gas gathered or purchased was based on the measured volume at an agreed upon location (generally at the wellhead). The volume of gas redelivered or sold at the tailgate of the Partnership’s processing facility would be lower than the volume purchased at the wellhead primarily due to NGLs extracted through processing. The Partnership would make up or “keep the producer whole” for the condensate and NGL volumes through the delivery of or payment for a thermally equivalent volume of residue gas. The cost of these natural gas volumes was recorded as a cost of natural gas, NGLs and condensate revenue-affiliates. The keep-whole contract conveyed an economic benefit to the Partnership when the combined value of the individual NGLs was greater in the form of liquids than as a component of the natural gas stream; however, the Partnership was adversely impacted when the value of the NGLs is lower as liquids than as a component of the natural gas stream. Certain contracts also included fee-based revenues for gathering and other midstream services. Cost of revenues were derived primarily from the purchase of natural gas, NGLs and condensates. There were no material costs categorized as cost of revenue directly identified with gathering, processing and other revenue.

Natural Gas Imbalances

The consolidated and combined balance sheets include natural gas imbalance receivables and payables caused by the difference in natural gas delivered to the Partnership’s customers and the natural gas contractually owed to the customers. Most natural gas imbalances are settled monthly in cash and calculated according to the terms of their

contracts. Changes in gas imbalances are reported net of the cost of product in the consolidated and combined statements of operations. There was no imbalance receivable as of December 31, 2014. As of December 31, 2013, the Partnership recorded an imbalance receivable of $0.1 million, which is recorded in accounts receivable in the consolidated and combined balance sheets.
Hedging and Derivatives
From time to time, the Partnership entered into derivative transactions to mitigate its exposure to price fluctuations in NGLs. The Partnership recognized all derivative instruments as either assets or liabilities in the combined balance sheet at

their respective fair value. For derivatives designated in hedging relationships, changes in the fair value were recognized in accumulated other comprehensive income, to the extent the derivative was effective at offsetting the changes in cash flows being hedged, until the hedged item affected earnings. As of the date of our IPO on July 31, 2013, we settled our outstanding interest rate swap and have discontinued our hedging and derivatives program.

Interest Rate Swaps

The Partnership utilizes derivative instruments to manage its exposure to interest rate risk. In January 2011, the Partnership entered into an interest rate swap for this purpose (“2011 Swap”). The 2011 Swap did not meet the criteria necessary to qualify for cash flow hedge accounting and was recorded at fair value at each reporting period with changes in fair value recognized currently in earnings. The 2011 Swap was settled in full on December 17, 2012. On December 17, 2012, the Partnership entered into a new interest rate swap (“2012 Swap”) to manage its exposure to interest rate risk. The 2012 Swap did not meet the criteria necessary to qualify for cash flow hedge accounting and is recorded at fair value at each reporting period with changes in fair value recognized currently in earnings. Gains and losses on interest rate swaps are recorded in gain (loss) on interest rate swap in the combined statements of operations.

Fair Value

FASB ASC 820, Fair Value Measurement, established a single authoritative definition of fair value when accounting rules require the use of fair value, set out a framework for measuring fair value and required additional disclosures about fair value measurements. The standard clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The standard utilizes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The following is a brief description of those three levels:

•Level 1-Quoted prices in active markets for identical assets or liabilities.
•Level 2-Other significant observable inputs (including quoted prices in active markets for similar assets or liabilities).
•Level 3-Significant unobservable inputs (including the Partnership’s own assumptions in determining fair value).

When the Partnership is required to measure fair value, and there is not a market-observable price for the asset or liability or a market- observable price for a similar asset or liability, the Partnership utilizes the cost, income, or market valuation approach depending on the quality of information available to support management’s assumptions.

The carrying amount of long-term debt reported on the consolidated and combined balance sheets approximates fair value, because of the variable rate nature of the Partnership’s long-term debt. The carrying amounts of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities reported on the consolidated and combined balance sheets approximate fair value due to the short-term nature of these items. The fair value of the Partnership’s accounts receivable with affiliates and accounts payable with affiliates cannot be determined due to the related party nature of these items. Derivative instruments are measured at fair value at each reporting period.

Asset Retirements Obligations

FASB ASC 410, Asset Retirement and Environmental Obligations, requires the Partnership to evaluate whether any future asset retirement obligations exist as of December 31, 2014 and 2013, and whether the expected retirement date of the related costs of retirement can be estimated. The Partnership has concluded that its natural gas gathering system assets, which include pipelines and treating facilities, have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. A liability for these asset retirement obligations will be recorded only if and when a future retirement obligation with a determinable life is identified. The Partnership did not record any asset retirement obligations as of December 31, 2014 and 2013 because the Partnership has no current intention of discontinuing use of any significant assets.

Environmental Expenditures

The operations of the Partnership are subject to various federal, state and local laws and regulations relating to the protection of the environment. Although the Partnership believes that it is in compliance with applicable environmental regulations, the risk of costs and liabilities are inherent in pipeline ownership and operation, and there can be no assurances that significant costs and liabilities will not be incurred by the Partnership.

Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Liabilities are recorded when the necessity for environmental remediation or other potential environmental liabilities become probable and the costs can be reasonably estimated. Management is not aware of any contingent liabilities that currently exist with respect to environmental matters.

Income Taxes

The Partnership is not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Therefore, income taxes are not levied at the entity level, but rather on the individual partners of the Partnership. Accordingly, the accompanying consolidated and combined financial statements do not include a provision for federal and state income taxes. The Partnership is subject to the Revised Texas Franchise Tax (“Texas Margin Tax”). The Texas Margin Tax is computed on modified gross margin and was $0.6 million, $0.1 million and $0.1 million for the years ended December 31, 2014, 2013 and 2012, and is recorded as Texas margin tax expense in the consolidated and combined statements of operations. The Partnership does not do business in any other state where a similar tax is applied. As of December 31, 2014, the Partnership had no liability recorded for unrecognized tax benefits.

Net Income Per Unit

The Partnership has omitted net income per unit for all historical periods prior to the IPO at July 31, 2013 because the Partnership operated under a sole member equity structure, which is different than the capital structure resulting from the consummation of the IPO and, as a result, the per unit data for periods prior to the IPO would not be meaningful to investors.

The net income per unit figures on the consolidated Statement of Operations for the year ending December 31, 2013 are based on the net income of the Partnership after the closing of the IPO on July 31, 2013 through December 31, 2013, since this is the amount of net income that is attributable to the Partnership units. Net income related to acquisitions from affiliates under common control for periods prior to the acquisition date are allocated 100% to the general partner in determining net income per unit.

Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, fines, penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred. Recoveries of environmental remediation costs from third parties that are probable of realization are separately recorded as assets, and are not offset against the related environmental liability.

Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study. Such accruals are adjusted as further information develops or circumstances change. Costs of expected future expenditures for environment remediation obligations are not discounted to their present value.

Transactions with Affiliates

From time to time, the Partnership enters into transactions with SEV related affiliates that have a common owner with the Partnership in order to reduce risk, create strategic alliances and supply or receive goods and services to these SEV related affiliates. As such, the accompanying consolidated and combined financial statements include costs that have been incurred by SEV on behalf of the Partnership. These amounts incurred by SEV are then billed or allocated to the Partnership and are classified on the consolidated and combined statements of operations as either direct operation and maintenance-affiliates or as general and administrative-affiliates.

At our IPO, the Partnership entered into an omnibus agreement with the general partner and its affiliates that addresses (i) the management and administrative services to be provided by NuDevco to the Partnership and the corresponding fees and expense reimbursements to be paid to NuDevco in connection therewith, (ii) the indemnification obligations between NuDevco and the Partnership for environmental and other liabilities and the operation of assets and (iii) the Partnership's right of first offer on certain of NuDevco Midstream Development's midstream energy assets. For additional information relating to transactions with our affiliates, please see Note 11, "Transactions with Affiliates," to our Consolidated Financial Statements included in this Form 10-K.

Use of Estimates and Assumptions

The preparation of the Partnership’s consolidated and combined financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated and combined financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could materially differ from those estimates. Significant items subject to such estimates by the Partnership's management include provisions for uncollectible receivables, valuation of long-lived assets and related estimated useful lives, valuation of derivatives, valuation of equity-based compensation, and reserves for contingencies.

Accounting for Awards under the Long-term Incentive Plan

The Long-term Incentive Plan ("LTIP") provides for the grant of unit options, unit appreciation awards, restricted units, phantom units, distribution equivalent rights, unit awards, profits interest units, and other unit-based awards. On August 1, 2013, phantom units, with distribution equivalent rights, of 292,000 units were awarded to certain employees of NuDevco Midstream Development and its affiliates who provide direct or indirect services to the Partnership pursuant to affiliate agreements, and 20,000 units were awarded to certain board members of the Partnership’s general partner. On December 5, 2014, phantom units, with distribution equivalent rights, of 215,000 units were awarded to certain employees of NuDevco Midstream Development and its affiliates who provide direct or indirect services to the Partnership pursuant to affiliate agreements, and 20,000 units were awarded to certain board members of the Partnership’s general partner. All of the phantom unit awards granted to-date are considered non-employee equity based awards and are required to be remeasured at fair market value at each reporting period and amortized to compensation expense on a straight-line basis over the vesting period of the phantom units with a corresponding increase in a liability. Management intends to settle the awards by allowing the recipient to choose between issuing the net amount of common units due, less common units equivalent to pay withholding taxes, due upon vesting with the Partnership paying the amount of withholding taxes due in cash or issuing the gross amount of common units due with the recipient paying the withholding taxes. The phantom unit awards were awarded to individuals who are not deemed to be employees of the Partnership.

Distribution equivalent rights are accrued for each phantom unit award as the Partnership declares cash distributions and are recorded as a decrease in partners’ capital with a corresponding liability in accordance with the vesting period of the underlying phantom unit, which will be settled in cash when the underlying phantom units vest.

Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. ASU 2014-09 will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective on January 1, 2017. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. We are evaluating the effect that ASU 2014-09 will have on our consolidated financial statements and related disclosures. We have not yet selected a transition method nor have we determined the effect of the standard on our ongoing financial reporting.

3. PARTNERSHIP EQUITY AND DISTRIBUTIONS

Outstanding Units

At December 31, 2014, the Partnership had outstanding common units of 8,979,248 and subordinated units of 8,724,545. NuDevco Midstream Development owns 100% of the interest in the Partnership’s general partner, which owns an approximate 2% general partner interest in the Partnership, 22% of the Partnership’s outstanding common units, representing an 11% interest in the Partnership, and 100% of the Partnership’s outstanding subordinated units, representing a 48% interest in the Partnership. See Note 5 (“Property, Plant and Equipment”) for discussion of common units and general partnership interest issued on August 1, 2014 in connection with the East New Mexico Dropdown.

At December 31, 2013, the Partnership had outstanding common units of 8,724,545 and subordinated units of 8,724,545. At December 31, 2013, NuDevco Midstream Development owned 100% of the interest in the Partnership’s general partner, which owns an approximate 2% general partner interest in the Partnership, 21% of the Partnership's outstanding common units, representing a 10% interest in the Partnership, and 100% of the Partnership’s outstanding subordinated units, representing a 49% interest in the Partnership.

Distributable Cash and Distributions

The partnership agreement requires the Partnership to distribute all available cash, as defined in its partnership agreement, to unitholders of record, as of the applicable record date, no later than 45 days after the end of each quarter.

Available cash generally means, for any quarter, all cash and cash equivalents on hand at the end of that quarter:

- less, the amount of cash reserves established by the General Partner to:
  - provide for the proper conduct of the business (including reserves for future capital expenditures and anticipated future debt service requirements and for anticipated shortfalls on future minimum commitment payments to which prior credits may be applied);
  - comply with applicable law, any of the Partnership's debt instruments or other agreements; or

provide funds for distributions to unitholders and to the general partner for any one or more of the next four quarters (provided that the general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent the Partnership from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);

- plus, if the general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

The Partnership declared the following cash distributions to its general and limited partners of record for the periods presented

In Thousands, except per-unit amounts Quarter ended:		Total Quarterly Distribution per Unit	Total Distribution (2)	Date of Distribution
December 31, 2014		$0.365	$6,593	February 11, 2015
September 30, 2014		$0.365	$6,593	November 4, 2014
June 30, 2014		$0.360	$6,469	August 5, 2014
March 31, 2014		$0.355	$6,375	May 6, 2014
December 31, 2013		$0.350	$6,232	February 3, 2014
September 30, 2013	(1)	$0.230	$4,095	November 4, 2013

(1) This distribution represents a prorated amount of the full minimum quarterly distribution of $0.35 per unit for each whole quarter based on the number of days between the closing of the Partnership's IPO on July 31, 2013 and September 30, 2013.

(2) Total distribution amount includes the distribution paid to our general partner and does not include the distribution equivalent rights ("DER") payments that accrue on all unvested phantom units that have been issued under our LTIP.

General Partner Interest

The Partnership’s general partner is entitled to 2% of all distributions made by the Partnership. If the Partnership issues additional units, the general partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership in order to maintain its 2% general partner interest. The 2% general partner interest, and the percentage of the Partnership’s cash distributions to which the general partner is entitled from such 2% interest, will be proportionately reduced if the Partnership issues additional units in the future (other than the issuance of common units upon conversion of outstanding subordinated units or the issuance of common units upon a reset of the incentive distribution rights) and the Partnership’s general partner does not contribute a proportionate amount of capital to the Partnership in order to maintain the general partner's 2% general partner interest.

Incentive Distribution Rights

NuDevco indirectly holds all of the incentive distribution rights ("IDRs") issued in the IPO. IDRs entitle NuDevco to receive an increasing percentage (13%, 23% and 48%) of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and certain target distribution levels have been achieved. The maximum distribution of 48% does not include any distributions that the Partnership’s general partner or its affiliates may receive on common, subordinated or general partner units that they own.

Subordinated Units and Common Units Held by NuDevco Midstream Development

The Partnership’s partnership agreement provides that, during the defined subordination period, the common units have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.35 per common unit before any distributions of available cash from operating surplus may be made on the subordinated units. The subordinated units are deemed “subordinated” because, for a defined period of time, holders of the subordinated units will not be entitled to receive any distributions until holders of the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages accrue or are payable on the subordinated units.

Except as described below, the subordination period began on the closing date of the IPO and extends until the first business day following the distribution of available cash in respect of any quarter beginning after September 30, 2016, that each of the following tests are met:

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distributions of available cash from operating surplus on each of the outstanding common units, subordinated units and general partner units equaled or exceeded $1.40 (the annualized minimum quarterly distribution), for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date;

- the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum of $1.40 (the annualized minimum quarterly distribution) on all of the outstanding common units, subordinated units and general partner units during those periods on a fully diluted basis; and

- there are no arrearages in payment of the minimum quarterly distribution on the common units.

4. NET INCOME PER UNIT

The net income per unit figures on the consolidated and combined Statement of Operations for the year ended December 31, 2013 are based on the net income of the Partnership after the closing of the offering on July 31, 2013 through December 31, 2013, since this is the amount of net income that is attributable to the newly issued common, general partner and subordinated units.

The Partnership's net income for periods subsequent to the IPO is allocated to the general partner and the limited partners in accordance with their respective ownership percentages and, when applicable, giving effect to incentive distributions allocable to the general partner. There were no incentive distributions allocable to NuDevco as of December 31, 2014 or 2013. Basic and diluted net income per unit is calculated by dividing the partner's interest in net income by the weighted average number of units outstanding during the period.

The following table illustrates the Partnership’s calculation of net income per unit for common and subordinated partner units. Net income attributable to the East New Mexico Dropdown for the period July 2, 2014 through July 31, 2014 is not allocated to the limited partners for purposes of calculating net income per limited partner unit.

	For the year ending December 31,	
	2014	2013
Net income (1)	$22,132	$7,190
Less: allocation of East New Mexico dropdown net income prior to acquisition	(160)	—
Less: general partner interest in net income	(435)	(144)
Limited partner interest in net income	$21,537	$7,046
Net income allocable to common units	$10,923	$3,523
Net income allocable to subordinated units	10,614	3,523
Limited partner interest in net income	$21,537	$7,046
Net income per limited partner common unit - basic	$1.23	$0.40
Net income per limited subordinated unit - basic	$1.22	$0.40
Net income per limited partner unit - basic	$1.22	$0.40
Net income per limited partner common unit - diluted	$1.21	$0.39
Net income per limited subordinated unit - diluted	$1.22	$0.40
Net income per limited partner unit - diluted	$1.21	$0.40
Weighted average limited partner units outstanding - basic		
Common units	8,902,295	8,724,545
Subordinated units	8,724,545	8,724,545
Total	17,626,840	17,449,090
Weighted average limited partner units outstanding - diluted		
Common units	9,026,734	9,036,545
Subordinated units	8,724,545	8,724,545
Total	17,751,279	17,761,090

(1) Post-IPO, August 1, 2013 to December 31, 2013 for the year ended December 31, 2013.

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MARLIN MIDSTREAM PARTNERS, LP
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5. PROPERTY, PLANT AND EQUIPMENT

Net property, plant and equipment are composed of the following:

In Thousands	Estimated Useful Lives (Years)	December 31, 2014	December 31, 2013
Gas processing plants (1)	5 – 40	$ 136,638	$ 133,859
Gathering pipelines and related equipment	5 – 40	52,591	47,728
Land and rights of way	—	11,818	11,043
Construction-in-progress	—	1,955	2,594
Information technology and other	2 – 10	2,065	1,548
Office building	15	306	306
Autos	5	472	357
Total		205,845	197,435
Accumulated depreciation		(43,687)	(34,887)
Property, plant and equipment, net		$ 162,158	$ 162,548

(1) Includes inlet and residue pipelines and connections.

The Partnership’s principal assets consist of two related natural gas processing facilities located in Panola County, Texas, a natural gas processing facility located in Tyler County, Texas, two natural gas gathering systems connected to its Panola County processing facilities and two NGL transportation pipelines that connect its Panola County and Tyler County processing facilities to third party NGL pipelines.

The Partnership's principal crude oil logistics assets consist of three crude oil transloading facilities: (i) its Wildcat facility located in Carbon County, Utah, where the Partnership currently operates one skid transloader and two ladder transloaders, (ii) its Big Horn facility located in Big Horn County, Wyoming, where the Partnership currently operates one skid transloader and one ladder transloader, and (iii) its East New Mexico facility located in Sandoval County, New Mexico, where the Partnership currently operates one skid transloader, which was acquired on August 1, 2014, as discussed below.

At the completion of the IPO, the Partnership transferred the Partnership’s 50% interest in the CO_2 processing facility located in Monell, Wyoming to affiliates of NuDevco. As such, subsequent to the closing of the IPO, the Partnership incurred no revenues or expenses associated with the Monell facility. The Partnership was responsible for the design and construction of the Monell facility. Anadarko was designated as an operator of the Monell facility with exclusive right to operate the facility until terminated by unanimous vote of the owners. Revenue generated from, and capital expenditures and operating expenses incurred, in connection with the operation of the plant were allocated on a pro-rata basis in proportion to each owner’s ownership interest. The Partnership recorded its proportional cost of the Monell facility and its share of revenues and expenses in its condensed consolidated and combined financial statements, as earned and incurred prior to the closing of the IPO, respectively.

For the years ended December 31, 2013 and 2012, the Partnership recorded revenues of $0.2 million and $1.2 million, respectively, and recorded expenses of $0.3 million and $0.4 million, respectively, attributable to the Monell facility in connection with the collaborative arrangement. These revenues are recorded in natural gas, NGLs and condensate revenue and the expenses are recorded in operation and maintenance in the consolidated and combined Statements of Operations.

On July 31, 2013, in connection with the IPO, the Partnership transferred property, plant and equipment, net of $3.2 million attributable to the Monell facility to affiliates of NuDevco.

The cost of property, plant and equipment classified as “Construction-in-progress” is excluded from costs being depreciated. These amounts represent property that is not yet suitable to be placed into productive service as of the respective balance sheet date.

Depreciation expense was $8.8 million, $8.2 million and $7.7 million for the years ended December 31, 2014, 2013 and 2012, respectively.

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MARLIN MIDSTREAM PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Acquisitions
On July 30, 2014, the Partnership entered into a Contribution Agreement with NuDevco Midstream Development and Marlin Midstream GP, LLC, the general partner of the Partnership, for the purchase of the East New Mexico Transloading Facility, located in Sandoval County, New Mexico, for $7.4 million. The purchase closed on August 1, 2014 and the total purchase price consisted of a $5.5 million cash payment and 89,720 Partnership common units issued to NuDevco Midstream Development, which were valued at the historical carrying value of the assets acquired of approximately $0.3 million. The assets acquired by the Partnership consist of one skid transloader and other miscellaneous equipment, which were subsequently assigned to Marlin Logistics. Additionally, the general partner of the Partnership made a capital contribution of $38,000 for the issuance of general partnership interest, to allow the general partner to maintain its 2% general partner interest in the Partnership.
The East New Mexico Dropdown represented a transaction between entities under common control. As a result, the consolidated and combined financial statements and related information presented herein have been recast to include the historical results of the East New Mexico Dropdown. Net income for the facility was approximately $0.2 million for the period July 2, 2014, the date operations commenced, through July 31, 2014. In addition, the Partnership recorded the assets of the East New Mexico Dropdown acquired at their historical carrying value to NuDevco Midstream Development on the date of acquisition. Any difference between consideration given and the historical carrying value of the assets is recognized as a reduction to partners' capital on a pro-rata basis. Cash consideration up to the historical carrying value of the assets acquired is presented as an investing activity and cash consideration in excess of the historical carrying value of the assets acquired is presented as a financing activity in the consolidated and combined Statements of Cash Flows.
In conjunction with the East New Mexico Dropdown, the Partnership entered into a three-year transloading services agreement with AES, effective August 1, 2014, requiring minimum monthly volume commitments for crude oil transloading services to be operated at the East New Mexico Transloading Facility.

6. LONG-TERM DEBT AND INTEREST EXPENSE
Long-term debt consists of the following:

In Thousands	December 31, 2014	December 31, 2013
Revolving credit facility	11,000	4,000
Total long-term debt	$11,000	$4,000

In October 2007, SEV and all of its subsidiaries (collectively, the “Borrowers”), including Marlin Midstream, entered into a credit agreement, which provided for a working capital facility, a term loan and a revolving credit facility (the “Credit Agreement”), as co-borrowers and were jointly and severally liable for amounts borrowed under the Credit Agreement. The Credit Agreement was secured by substantially all of the assets of SEV and its subsidiaries, including all of Marlin Midstream’s assets.
The Credit Agreement was amended on May 30, 2008 to provide for a $177.5 million working capital facility, a $100.0 million term loan, and a $35.0 million revolving credit facility. On January 24, 2011, the Borrowers amended and restated the Credit Agreement (the “Fifth Amended Credit Agreement”) to decrease the working capital facility to $150.0 million, to increase the term loan to $130.0 million and to eliminate the revolving credit facility.
On December 17, 2012, the Borrowers amended and restated the Fifth Amended Credit Agreement to decrease the working capital facility to $70.0 million, to decrease the term loan to $125.0 million and to reinstate the revolving credit facility in the amount of $30.0 million (the “Sixth Amended Credit Agreement”). The Sixth Amended Credit Agreement was scheduled to mature on December 17, 2014.
Although Marlin Midstream was jointly and severally liable for SEV’s borrowings, Marlin Midstream did not historically have access to the working capital facility, but was the primary recipient of the proceeds from the term loan and revolving credit facility.
The Partnership applied ASU 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (“ASU 2013-04”), which

prescribes the accounting for joint and several liability arrangements. This guidance requires an entity to measure its obligation resulting from joint and several liability arrangements for which the total amount under the arrangement is fixed at the reporting date, as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. Based on the Sixth Amended Credit Agreement and understanding among the Borrowers, the term loan and the revolving credit facility were assigned specifically to Marlin Midstream. The Partnership recognized the proceeds from the term loan and the revolving credit facility on its combined Balance Sheet at December 31, 2014 in the amount of $126.5 million, which represented the amounts Marlin Midstream agreed with the other borrowers to pay, and the amounts Marlin Midstream expected to pay.

Term Loan and Revolving Credit Facility

Term loan

The term loan consisted of $130.0 million in 2011 under the Fifth Amended Credit Agreement and was later amended on December 17, 2012 under the Sixth Amended Credit Agreement. The term loan consisted of outstanding borrowings of $125.0 million as of December 31, 2012 under the Sixth Amended Credit Agreement. The term loan required quarterly principal payments of $1.6 million to maturity, with the balance of $112.5 million due on December 17, 2014.

Under the Sixth Amended Credit Agreement, Marlin Midstream may have elected to have loans under the term loan bear interest either (i) at a Eurodollar based rate plus a margin ranging from 3.50% to 4.25% depending on SEV’s consolidated funded indebtedness ratio then in effect, or (ii) at a base rate loan plus a margin ranging from 2.50% to 3.25% depending on SEV’s consolidated funded indebtedness ratio then in effect.

The interest rate for the term loan was 3.96% at December 31, 2012. The Sixth Amended Credit Facility was repaid on July 31, 2013 with funds received from the IPO and borrowings under the Partnership's new credit facility.

Revolving credit facility

The revolving credit facility was reinstated on December 17, 2012 with a borrowing capacity of $30.0 million as part of the Sixth Amended Credit Agreement. The outstanding balance on the revolving credit facility at December 31, 2014 was $1.5 million. The revolving credit facility outstanding principal was due on December 31, 2014.

The unused portion of the revolving credit facility was subject to a commitment fee of 0.50%. The interest rate was 3.96% at December 31, 2012. The Sixth Amended Credit Facility was repaid on July 31, 2013 with funds received from the IPO and borrowings under the Partnership's new credit facility.

New Credit Facility

Concurrently with the closing of our IPO, the Partnership entered into a $50.0 million senior secured revolving credit facility, which matures on July 31, 2017. If no event of default has occurred, the Partnership has the right, subject to approval by the administrative agent and certain lenders, to increase the borrowing capacity under the new revolving credit facility to up to $150.0 million. The new credit facility is available to fund expansions, acquisitions and working capital requirements for our operations and general Partnership purposes.

At the Partnership's election, interest will be generally determined by reference to:

- the Eurodollar rate plus an applicable margin between 3.0% and 3.75% per annum (based upon the prevailing senior secured leverage ratio); or
- the alternate base rate plus an applicable margin between 2.0% and 2.75% per annum (based upon the prevailing senior secured leverage ratio). The alternate base rate is equal to the highest of Société Générale’s prime rate, the federal funds rate plus 0.5% per annum or the reference Eurodollar rate plus 1.0%.

The revolving credit facility is secured by the capital stock of our present and future subsidiaries, all of our and our subsidiaries’ present and future property and assets (real and personal) control agreements relating to our and our subsidiaries’ bank accounts and collateral assignments of our and our subsidiaries’ material construction, ownership and operation agreements, including any agreements with AES or Anadarko.

At the closing of the IPO, the Partnership borrowed $25.0 million under the new revolving credit facility, a portion of which, along with the proceeds from the IPO, were used to repay approximately $131.9 million of outstanding borrowings under the previous credit facility. Immediately upon repayment, the previous credit facility was terminated. At December 31, 2014, the Partnership had $11.0 million outstanding on the senior secured revolving credit facility.

The Partnership's revolving credit facility also contains covenants that, among other things, require it to maintain specified ratios or conditions. The Partnership must maintain a consolidated senior secured leverage ratio, consisting of consolidated indebtedness under its revolving credit facility to consolidated EBITDA of not more than 4.0 to 1.0, as of the last day of each fiscal quarter. In addition, the Partnership must maintain a consolidated interest coverage ratio, consisting of its consolidated EBITDA minus capital expenditures to its consolidated interest expense, letter of credit fees and commitment fees of not less than 2.5 to 1.0, as of the last day of each fiscal quarter. As of December 31, 2014, the Partnership was in compliance with all debt covenants.

In addition, the Partnership's revolving credit facility contains affirmative covenants that are customary for credit facilities of this type. The covenants will include delivery of financial statements and other information (including any filings made with the SEC), maintenance of property and insurance, payment of taxes and obligations, material compliance with laws, inspection of property, books and records and audits, use of proceeds, payments to bank blocked accounts, notice of defaults and certain other customary matters.

Debt Maturities

Principal amounts of long-term debt under the new senior secured revolving credit facility mature on July 31, 2017.

Deferred Financing Costs

Deferred financing costs were $0.7 million and $1.0 million as of December 31, 2014 and 2013, respectively. Of these amounts, $0.3 million and $0.3 million are included in other current assets within both of the consolidated Balance Sheets at December 31, 2014 and 2013, and $0.4 million and $0.7 million are included in other assets within the consolidated Balance Sheets at December 31, 2014 and 2013, respectively, based on the term of the related debt obligations.

Amortization of deferred financing costs was $0.3 million, $0.5 million and $0.4 million for the years ended December 31, 2014, 2013 and 2012, respectively. Amortization of deferred financing costs is recorded in interest expense, net of amounts capitalized, in the consolidated and combined Statements of Operations.

In conjunction with executing the Sixth Amended Credit Agreement in December 2012, the Partnership paid $1.0 million of financing costs, of which $0.9 million was capitalized and $0.1 million was expensed immediately in general and administrative expenses in the consolidated and combined Statements of Operations. Simultaneously, the Partnership expensed $0.2 million of existing unamortized deferred financing costs related to the Fifth Amended Credit Agreement, which is recorded in interest expense in the consolidated and combined Statements of Operations.

In conjunction with executing the current revolving credit facility on July 31, 2013, the Partnership paid $1.1 million of financing costs, all of which were capitalized. Simultaneously, the Partnership expensed $0.8 million of existing unamortized deferred financing costs related to the Sixth Amended Credit Agreement, which is recorded in interest expense in the consolidated and combined Statements of Operations.

Interest Expense

A reconciliation of total interest expense to “interest expense, net of amounts capitalized” as reported in the consolidated and combined Statements of Operations for the years ended December 31, 2014, 2013 and 2012 is as follows:

In Thousands	Years Ended December 31,		
	2014	2013	2012
Interest expense on long-term debt	$526	$3,312	$4,599
Interest expense from amortization of deferred financing costs	285	508	365
Interest expense from write-off of unamortized deferred financing costs	—	761	177
Less interest expense capitalized	(45)	(232)	(214)
Total interest expense, net of amounts capitalized	$766	$4,349	$4,927

7. DERIVATIVE FINANCIAL INSTRUMENTS

The Partnership historically used interest-rate related derivative instruments to manage its exposure related to changes in interest rates on its variable rate debt instruments and periodically used commodity derivatives to manage its exposure to commodity price fluctuations. The Partnership does not enter into speculative or trading derivative instruments.

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By using derivative financial instruments to hedge exposures to changes in interest rates and commodity prices, the Partnership exposed itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract was positive, the counterparty owed the Partnership, which created credit risk for the Partnership. When the fair value of the derivative contract was negative, the Partnership owed the counterparty, and therefore, the Partnership was not exposed to the counterparty's credit risk in those circumstances. The Partnership minimized counterparty credit risk in derivative instruments by entering into transactions with high-quality counterparties. The derivative instruments entered into by the Partnership did not contain credit-risk-related contingent features.

Market risk is the adverse effect on the fair value of a derivative instrument that results from a change in the underlying interest rates or commodity prices. For derivative instruments where hedge accounting is utilized, unrealized gains and losses recognized on derivative instruments due to changes in the fair value of the derivative instruments will offset corresponding realized gains and losses on the related hedged item. Unrealized gains or losses are recognized on the derivative instruments, to the extent the hedge is effective, are deferred in other comprehensive income, and recognized in income when the underlying hedged transaction is recognized. For derivative instruments where hedge accounting is not utilized, unrealized gains and losses due to changes in the fair value of the derivative instruments are recognized currently in earnings and may not fully offset current period realized gain or losses on the related hedged item. The market risk associated with interest rate and commodity price contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken.

The Partnership maintains a commodity-price-risk management strategy that allows for the use of derivative instruments to minimize significant unanticipated earnings fluctuations caused by commodity-price-volatility. Since the Partnership has entered into primarily fee-based contracts, the Partnership did not have any outstanding commodity-price related derivative instruments as of December 31, 2014 and 2013.

Commodity Derivatives

The Partnership was historically exposed to market risk from changes in energy commodity prices within its operations. The Partnership sold NGL volumes received as compensation for processing services and also bought natural gas to satisfy the required fuel and shrink needed to recover NGLs. To reduce exposure to a decrease in revenues from fluctuations in NGL market prices or increases in costs and operating expenses from fluctuations in natural gas market prices, the Partnership, at times, entered into NGL or natural gas derivative contracts to mitigate the price risk on forecasted sales of NGLs and purchases of natural gas. The Partnership's NGL derivatives were designated as cash flow hedges, while its natural gas derivatives did not qualify for hedge accounting despite hedging its future cash flows on an economic basis.

Changes in the fair value of commodity derivatives that were not designated as cash flow hedges were recorded within cost of revenues—affiliates in the consolidated and combined Statements of Operations. Changes in the fair value of designated cash flow hedges, to the extent effective, were deferred in other comprehensive income and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affected earnings, or when it was probable that the hedged forecasted transaction would not occur by the end of the originally specified time period. Settlements of derivatives were included in cash flows from operating activities for the Partnership. The Partnership has no outstanding commodity derivative instruments at December 31, 2014 or 2013.

Interest Rate Swap

On January 24, 2011, Marlin Midstream entered into an interest rate swap ("2011 Swap"). The 2011 Swap paid a fixed rate and received a floating rate in order to fix the interest rate on the Partnership's term loan and was scheduled to mature on January 24, 2014. The notional amount of the 2011 Swap as of December 31, 2011 was $100.0 million.

On December 17, 2012, Marlin Midstream terminated the 2011 Swap and entered into a new interest rate swap ("2012 Swap") in order to fix a portion of the interest rate on Marlin Midstream's amended term loan. Marlin Midstream paid a fixed rate and received a floating rate under the 2012 Swap. The maturity date of the 2012 Swap was December 17, 2014, and the notional amount of the 2012 Swap at December 31, 2012 was $62.5 million. On July 31, 2013, in connection with the Partnership's IPO, the 2012 Swap was settled for approximately $0.1 million.

Marlin Midstream's interest rate swaps did not meet the criteria necessary to qualify for cash flow hedge accounting and were recorded at fair value at each reporting period with the associated unrealized gain or loss recorded in gain (loss) on interest rate swap in the consolidated and combined Statements of Operations.

As of December 31, 2014 and 2013, respectively, there are no derivative assets and liabilities, including balances for designated and undesignated hedge activities, as the Partnership did not have any open derivative instruments designated as cash flow hedges at December 31, 2014 and 2013, respectively.

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The following table presents the net realized and unrealized gains (losses) recognized in net income for derivative instruments not designated as hedging instruments:

In Thousands

Description of Derivatives	Statement of Operations Location	Years Ended December 31, 2014	2013	2012
Natural gas option contracts	Cost of revenues—affiliates	$—	$—	$(87)
Interest rate swap contracts	Gain (loss) on interest rate swap	$—	$(48)	$(851)
Total loss recognized in income		$—	$(48)	$(938)

The following table presents the gain for NGL forward contracts designated and accounted for as cash flow hedges, as recognized in other comprehensive income and cost of revenues—affiliates:

In Thousands

Description of Derivatives	Location	Years Ended December 31, 2014	2013	2012
Gain recognized in accumulated other comprehensive income	Accumulated other comprehensive income	$—	$—	$689
Gain reclassified from accumulated other comprehensive income to income	Cost of revenues—affiliates	$—	$—	$(752)

As of December 31, 2014 and 2013, respectively, there are no deferred gains or losses remaining in accumulated other comprehensive income as the Partnership did not have any open derivative instruments designated as cash flow hedges at December 31, 2014 and 2013, respectively.

8. FAIR VALUE OF FINANCIAL INSTRUMENTS

FASB ASC 820, Fair Value Measurement, established a single authoritative definition of fair value when accounting rules require the use of fair value, set out a framework for measuring fair value and required additional disclosures about fair value measurements. The standard clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The standard utilizes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three broad levels. The following is a brief description of those three levels:

- Level 1—Quoted prices in active markets for identical assets or liabilities.
- Level 2—Other significant observable inputs (including quoted prices in active markets for similar assets or liabilities).
- Level 3—Significant unobservable inputs (including the Partnership’s own assumptions in determining fair value).

When the Partnership is required to measure fair value, and there is not a market-observable price for the asset or liability or a market-observable price for a similar asset or liability, the Partnership utilizes the cost, income, or market valuation approach depending on the quality of information available to support management’s assumptions. Financial instruments are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Partnership’s assessment of the significance of a particular input to the fair value requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

The Partnership had no financial instruments at December 31, 2014 and 2013. At the IPO date, the Partnership settled the outstanding 2012 Swap.

The estimated fair value of accounts receivable, accounts receivable - affiliates, accounts payable, accounts payable - affiliates and accrued liabilities approximate their carrying values due to their short-term nature. The estimated fair value of the Partnership’s outstanding long-term debt approximates carrying value due to the variable rate nature of the Partnership’s long-term debt.

MARLIN MIDSTREAM PARTNERS, LP
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9. SEGMENT INFORMATION

The Partnership's revenues are derived from two operating segments: (i) gathering and processing and (ii) logistics. These segments are monitored separately by management for performance and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment, and expertise required for their respective operations. Gross margin is a primary performance measure used by management. The Partnership defines gross margin as revenues less costs of revenues. Gross margin should not be considered an alternative to, or more meaningful than, operating income as determined in accordance with generally accepted accounting principles.

The following tables present financial information by segment for the years ended December 31, 2014 and 2013. Our crude oil logistics segment had no material assets, liabilities, or operations prior to the Partnership's IPO.

Year ended December 31, 2014

In Thousands	Gathering & Processing	Logistics	Corporate and Consolidation	Marlin Midstream Partners, LP
Total revenues	$59,926	$15,302	$—	$75,228
Cost of revenues	17,348	—	—	17,348
Gross margin	42,578	15,302	—	57,880
Operation and maintenance	12,828	2,087	652	15,567
General and administrative	—	—	8,669	8,669
Other operating expenses	10,097	96	—	10,193
Operating income	19,653	13,119	(9,321)	23,451
Interest expense, net of amounts capitalized	—	—	(766)	(766)
Gain (loss) on interest rate swap	—	—	—	—
Net income before tax	19,653	13,119	(10,087)	22,685
Income tax expense	—	—	553	553
Net income (loss)	$19,653	$13,119	$(10,640)	$22,132

Year ended December 31, 2013

In Thousands	Gathering & Processing	Logistics	Corporate and Consolidation	Marlin Midstream Partners, LP
Total revenues	$47,052	$5,808	$—	$52,860
Cost of revenues	13,999	—	—	13,999
Gross margin	33,053	5,808	—	38,861
Operation and maintenance	14,424	613	854	15,891
General and administrative	—	—	7,886	7,886
Other operating expenses	9,390	23	—	9,413
Operating income	9,239	5,172	(8,740)	5,671
Interest expense, net of amounts capitalized	—	—	(4,349)	(4,349)
Gain (loss) on interest rate swap	—	—	(48)	(48)
Net income before tax	9,239	5,172	(13,137)	1,274
Income tax expense	—	—	88	88
Net income (loss)	$9,239	$5,172	$(13,225)	$1,186

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The following table presents financial information by segment at December 31, 2014 and 2013, respectively:

Balance Sheet at December 31, 2014

In Thousands	Gathering & Processing	Logistics	Corporate and Consolidation	Marlin Midstream Partners, LP
Assets:				
Current assets	$4,268	$1,733	$3,064	$9,065
Property, plant and equipment, net	161,389	769	—	162,158
Other assets	163	—	452	615
Total Assets	$165,820	$2,502	$3,516	$171,838
Liabilities and Partners’ Capital				
Total current liabilities	$1,323	$132	$4,085	$5,540
Total long-term liabilities	—	—	11,868	11,868
Total Liabilities	1,323	132	15,953	17,408
Partners’ Capital	164,497	2,370	(12,437)	154,430
Total Liabilities and Partners’ Capital	$165,820	$2,502	$3,516	$171,838

Balance Sheet at December 31, 2013

In Thousands	Gathering & Processing	Logistics	Corporate and Consolidation	Marlin Midstream Partners, LP
Assets:				
Current assets	$5,727	$1,195	$3,772	$10,694
Property, plant and equipment, net	162,029	519	—	162,548
Other assets	163	—	737	900
Total Assets	$167,919	$1,714	$4,509	$174,142
Liabilities and Partners’ Capital				
Total current liabilities	$2,796	$353	$6,077	$9,226
Total long-term liabilities	—	—	4,366	4,366
Total Liabilities	2,796	353	10,443	13,592
Partners’ Capital	165,123	1,361	(5,934)	160,550
Total Liabilities and Partners’ Capital	$167,919	$1,714	$4,509	$174,142

10. COMMITMENTS AND CONTINGENCIES

The Partnership has reserved capacity of 3,500 barrels a day at a third-party fractionator. If the Partnership fails to deliver 95% of the reserved capacity, the Partnership is obligated to pay a fixed fee. The maximum total fixed fee that the Partnership would be obligated to pay is approximately $2.2 million per year through the end of the contract, which expires April 30, 2015. Under the three-year fee-based commercial agreement with AES, the Partnership is reimbursed for a majority of any deficiency payments accrued under the reserved capacity agreement. The Partnership recorded $0.9 million and $0.5 million of expense, net of deficiency reimbursements, for the twelve months ended December 31, 2014 and 2013, respectively, for deficiency payments for under-delivery of volumes. No payments were accrued or paid in 2012.

From time to time, the Partnership may be involved in legal, tax, regulatory and other proceedings in the ordinary course of business. Management does not believe that the Partnership is a party to any litigation that will have a material impact on its financial condition or results of operations.

11. TRANSACTIONS WITH AFFILIATES

From time to time, the Partnership enters into transactions with SEV related affiliates that have a common owner with the Partnership in order to reduce risk, create strategic alliances and supply or receive goods and services to these SEV related affiliates. For additional information relating to transactions with our affiliates coinciding with the closing of the IPO, please see Note 1, "Organization".

Accounts receivable from and accounts payable to affiliates

The Partnership had receivables due from affiliates of $4.0 million and $3.6 million at December 31, 2014 and 2013, respectively. Receivables due from affiliates primarily related to our fee-based gathering and processing agreements with SEV and AES, and our fee-based transloading services agreement with AES. Payables to affiliates were $1.4 million and $1.6 million at December 31, 2014 and 2013, respectively. Payables to affiliates primarily related to settlements under our gathering and processing agreements with SEV and AES and reimbursement to an affiliate of NuDevco for certain general and administrative and operating costs under the omnibus agreement with NuDevco. Long-term incentive plan-payable to affiliates represents amounts accrued related to equity-based compensation to affiliate employees and directors.

Revenues and cost of revenues

Prior to the IPO on July 31, 2013, the Partnership provided processing services for a subsidiary of SEV, whereby the Partnership gathered natural gas from third parties, extracted NGLs, and redelivered the processed natural gas to the subsidiary of SEV. Under certain third-party contracts, the Partnership transferred all natural gas purchased to the subsidiary of SEV at market price. The Partnership also replaced energy used in processing due to the extraction of liquids, compression and transportation of natural gas, and fuel by purchasing natural gas from a subsidiary of SEV at the same market price. The Partnership used the MMBtu volume to measure how much energy is used in processing. Cost of natural gas, NGLs and condensate revenue—affiliates included in the Partnership’s results of operations for the years ended December 31, 2013 and 2012 from these agreements was $3.0 million and $7.7 million, respectively.

Additionally, the Partnership has entered into a gas transportation agreement with a subsidiary of SEI. The Partnership receives the higher of (i) a minimum monthly payment or (ii) a transportation fee per MMBtu times actual volumes delivered. The current transportation agreement was set to expire on February 28, 2013, but was extended for three additional years at a fixed rate per MMBtu without a minimum monthly payment. Included in the Partnership’s results of operations for the years ended December 31, 2014, 2013 and 2012 are gathering, processing and other revenue—affiliates of less than $0.1 million, less than $0.1 million, and $0.3 million, respectively, related to these transactions.

The Partnership currently has in place a three-year fee-based commercial agreement with AES, requiring a minimum monthly volume commitment of 100 MMcf/d. This agreement became effective August 1, 2013. Included in the Partnership's results of operations for the year ended December 31, 2014 and 2013 are gathering, processing, transloading and other revenue—affiliates of $22.7 million and $7.2 million, respectively, related to this agreement. Cost of natural gas, NGLs and condensate revenue - affiliates included in the Partnership’s results of operations for the year

ended December 31, 2014 and 2013 related to this agreement were $12.6 million and $2.5 million, respectively.
In connection with the IPO, the Partnership entered into three-year transloading services agreements with AES, requiring minimum monthly volume commitments for crude oil transloading services. In connection with the East New Mexico

dropdown (see Note 5, "Property, Plant and Equipment"), the Partnership entered into a three-year transloading services agreement with AES, requiring minimum monthly volume commitments for transloading services. Included in the Partnership's results of operations for the year ended December 31, 2014 and 2013 are gathering, processing, transloading and other revenue—affiliates of $15.3 million and $5.8 million, respectively, related to these agreements.

Cost allocations

Prior to the IPO, SEV and its affiliates had paid certain expenses on behalf of the Partnership, such as insurance, professional fees, and financing fees. These expenses were reimbursed by the Partnership to SEV and its affiliates and are included in operation and maintenance—affiliates and general and administrative—affiliates in the consolidated and combined Statements of Operations. In addition, SEV and its affiliates have allocated certain overhead costs associated with general and administrative services, including facilities, information services, human resources and other support departments to the Partnership. Where costs incurred on the Partnership's behalf could not be determined by specific identification, the costs were primarily allocated to the Partnership based on percentage of departmental usage, wages or headcount. The Partnership believes these allocations were a reasonable reflection of the utilization of services provided. However, the allocations may not fully reflect the expenses that would have been incurred had the Partnership been a stand-alone company during the periods presented prior to the IPO.

At the closing of the IPO, the Partnership entered into an omnibus agreement with NuDevco and its affiliates which addresses the management and administrative and overhead services to be provided by NuDevco to the Partnership and the corresponding fees and expense reimbursements to be paid to NuDevco in connection therewith. Under the omnibus agreement, the Partnership pays an annual fee, currently in the amount of $0.6 million, for executive management services.

The total amount charged to the Partnership for direct reimbursement of operating and overhead cost allocations, which is recorded in operation and maintenance—affiliates, for the years ended December 31, 2014, 2013 and 2012 was $6.7 million, $3.5 million and $0.8 million, respectively. The total amount charged to the Partnership for direct reimbursement of administrative and overhead cost allocations, which is recorded in general and administrative—affiliates, for the years ended December 31, 2014, 2013 and 2012 was $5.1 million, $4.2 million and $1.0 million, respectively. Amounts incurred by the Partnership for the years ended 2014 and 2013 include expense for the Marlin Midstream Partners, LP 2013 Long-Term Incentive Plan ("LTIP").

Capital Contributions

During the seven months prior to the IPO on July 31, 2013 and for the twelve months ended December 31, 2012, the Partnership received capital contributions of $3.6 million and $4.4 million, respectively, from its sole member.

12. EQUITY BASED COMPENSATION

In connection with the IPO, the board of directors of the Partnership's general partner adopted the LTIP. Individuals who are eligible to receive awards under the LTIP include (1) employees of the Partnership and NuDevco Midstream Development and its affiliates, (2) directors of the Partnership's general partner, and (3) consultants. The LTIP provides for the grant of unit options, unit appreciation awards, restricted units, phantom units, distribution equivalent rights, unit awards, profits interest units, and other unit-based awards. The maximum number of common units issuable under the LTIP is 1,750,000.

On August 1, 2013, phantom units, with distribution equivalent rights, of 292,000 units were awarded to certain employees of NuDevco Midstream Development and its affiliates who provide direct or indirect services to the Partnership pursuant to affiliate agreements, and 20,000 units were awarded to certain board members of the Partnership's general partner. On December 5, 2014, phantom units, with distribution equivalent rights, of 215,000 units were awarded to certain employees of NuDevco Midstream Development and its affiliates who provide direct or indirect services to the Partnership pursuant to affiliate agreements, and 20,000 units were awarded to certain board members of the Partnership's general partner. All of the phantom unit awards granted to-date are considered non-employee equity based awards and are required to be remeasured at fair market value at each reporting period and amortized to compensation expense on a straight-line basis over the vesting period of the phantom units with a corresponding increase in a liability. Management intends to settle the awards by allowing the recipient to choose between issuing the net amount of common units due, less common units equivalent to pay withholding taxes, due upon vesting with the Partnership paying the amount of withholding taxes due in cash or issuing the gross amount of common units due with the recipient paying the withholding taxes. The phantom unit awards were awarded to individuals who are not deemed to be employees of the Partnership.

Distribution equivalent rights are accrued for each phantom unit award as the Partnership declares cash distributions and are recorded as a decrease in partners' capital with a corresponding liability in accordance with the vesting period of the underlying phantom unit, which will be settled in cash when the underlying phantom units vest. At December 31, 2014 and 2013, a liability of approximately $48,000 and $32,000, respectively, was recorded for distributions associated with unvested phantom units under our LTIP plan.

For those employees of NuDevco Midstream Development or its affiliates who had attained five or more years of service at the grant date of August 1, 2013, the phantom units awarded fully vested on February 15, 2014. For those employees of NuDevco Midstream Development who had not attained five or more years of service with NuDevco Midstream Development or its affiliates at the grant date of August 1, 2013, the phantom units awarded will vest in five equal annual installments. The first installment vested on June 30, 2014. The phantom units awarded on August 1, 2013 to board members of the Partnership's general partner fully vested on February 15, 2014.

The phantom units awarded to employees of NuDevco Midstream Development or its affiliates on December 5, 2014 will vest in three equal annual installments with the first installment vesting on June 30, 2015. The phantom units awarded on December 5, 2014 to board members of the Partnership's general partner fully vested on February 15, 2015.

For the years ended December 31, 2014 and 2013, approximately $1.3 million and $2.1 million, respectively, in compensation expense was recorded in general and administrative expenses - affiliates and approximately $0.7 million and $0.9 million, respectively, in compensation expense was recorded in operation and maintenance - affiliates in the consolidated Statement of Operations. No compensation expense was recorded for the same periods in 2012 as there were no LTIP awards outstanding. A summary of the phantom units activity for the year ended December 31, 2014 is presented below:

	Number of shares	Weighted Average Grant-Date Fair Value
Total Non-vested at January 1, 2014	312,000	$20.00
Granted	235,000	19.42
Vested	(222,600)	20.00
Forfeited or canceled	(26,000)	20.00
Total Outstanding at December 31, 2014	298,400	$19.54

Unrecognized compensation expense associated with the unvested phantom units at December 31, 2014 was approximately $4.5 million and is expected to be recognized over a weighted average period of approximately 2.5 years.

13. CONCENTRATIONS OF CREDIT RISK

Substantially all of the Partnership's receivables are from companies in a similar industry and include independent exploration and production companies, pipeline companies and marketers. The industry concentration of these customers may impact the Partnership's overall exposure to credit risk, either positively or negatively, as its customers may be similarly affected by changes in commodity prices, regulation and other economic factors. The Partnership performs credit analysis in order to monitor its credit risks and ensure that its customers are creditworthy.

Following the closing of the IPO, the Partnership's revenues are mainly derived from fees earned from minimum capacity agreements for its midstream operations, which includes gathering and processing fees, and fees earned from its minimum capacity transloading agreements. In addition, the Partnership derives revenues from the sale of NGLs produced from natural gas processing. Total revenues from two third-party customers and one affiliate customer constituted approximately 98% of total revenues for the year ended December 31, 2014 and 2013.

Prior to the IPO, the Partnership's revenues were derived mainly from the sale of NGLs produced from natural gas processing and fees earned from its midstream operations including gathering and processing. Revenues from two third-party customers constituted approximately 93% of total revenues for the years ended December 31, 2012. The Partnership had contractual arrangements with both customers negotiated at standard commercial terms for the provision of services and/or sale of NGLs with remaining terms ranging from one to five years.

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14. INCOME TAX

The Partnership is not a taxable entity for U.S. federal income tax purposes or for the majority of states that impose an income tax. Therefore, income taxes are not levied at the entity level, but rather on the individual partners of the Partnership. Accordingly, the accompanying consolidated and combined financial statements do not include a provision for federal and state income taxes. The Partnership is subject to the Revised Texas Franchise Tax (“Texas Margin Tax”). The Texas Margin Tax is computed on modified gross margin and current income tax expense was $0.2 million, $0.1 million and $0.1 million for the years ended December 31, 2014, 2013 and 2012, and deferred income tax expense was $0.4 million for the year ended December 31, 2014. At December 31, 2014 and 2013, there was $0.4 million and $0.1 million, respectively, of non-current deferred income tax liabilities related to property, plant and equipment. The Partnership does not do business in any other state where a similar tax is applied.

15. SUBSEQUENT EVENTS

Fourth Quarter 2014 Distribution

On January 23, 2015, the Partnership announced that the board of directors of its general partner declared a quarterly cash distribution of $0.365 per unit, or $1.46 on an annualized basis, to unitholders of record as of February 6, 2015. The Partnership paid the quarterly distribution to unitholders on February 11, 2015.

Sale of General Partner Interest and Contribution of the Legacy Gathering System

On February 27, 2015, the Partnership consummated a Transaction Agreement (the “Transaction Agreement”) by and among the Partnership, Azure Midstream Energy LLC, a Delaware limited liability company that is wholly owned by Azure Midstream Holdings LLC (collectively “Azure”), the General Partner, NuDevco, and Marlin IDR Holdings (“IDRH”).

The consummation of the Transaction Agreement resulted in the Partnership acquiring the Legacy System from Azure and Azure receiving $92.5 million in cash and acquiring 100% of the equity interests in the GP and 90% of the Partnership’s incentive distribution rights (“IDRs”).

The Transaction Agreement occurred in the following steps:

- The Partnership (i) amended and restated its partnership agreement to reflect the unitization of all of the Partnership’s incentive distribution rights (as unitized, the “IDR Units”) and (ii) recapitalize the incentive distribution rights owned by IDRH into 100 IDR Units.
- The Partnership redeemed 90 IDR Units held by IDRH in exchange for a payment by the Partnership of $63.0 million to IDRH (the “Redemption”).
- Azure contributed the Legacy System to the Partnership through the contribution, indirectly or directly, of (i) all of the outstanding general and limited partner interests in Talco Midstream Assets, Ltd., a Texas limited liability company and subsidiary of Azure (“Talco”), and (ii) certain assets (the “TGG Assets”) owned by TGG Pipeline, Ltd., a Texas limited liability company and subsidiary of Azure (“TGG”), in exchange for aggregate consideration of $162.5 million, which was paid to Azure in the form of a cash payment of $99.5 million and in the form of the issuance of 90 IDR Units (the foregoing transaction, collectively, the “Contribution”).
- Azure purchased from NuDevco (i) all of the outstanding membership interests in the GP (the “GP Purchase,”) for $7.0 million and (ii) an option to acquire up to 20% of each of the common units and subordinated units of the Partnership held by NuDevco as of the execution date of the Transaction Agreement (the “Option,” together with the Redemption, Contribution and GP Purchase, the “Transactions”). As a result, NuDevco no longer controls the Partnership.

The Legacy System consists of approximately 658 miles of high-and low-pressure gathering lines and serves approximately 100,000 dedicated acres within Harrison, Panola and Rusk counties in Texas and Caddo parish in Louisiana and currently serves the Cotton Valley formation, the Haynesville shale formation and the shallower producing sands in the Travis Peak formation. The Legacy System has access to seven major downstream markets, three third-party processing plants and the Panola County processing plants. The combination of the Partnership's natural gas processing assets and the Legacy System's gathering assets creates a diverse platform of midstream services and establishes the Partnership as one of the largest gathering and processing systems in the Cotton Valley formation in east Texas and north Louisiana.

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MARLIN MIDSTREAM PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Because the financial information associated with this transaction has not been finalized as of the date that our consolidated financial statements were available to be issued, the related unaudited supplemental pro forma information has not been provided.

New Senior Secured Revolving Credit Facility

Contemporaneously with the Transactions, the Partnership entered into a new senior secured revolving credit facility (the “Senior Credit Facility”) with Wells Fargo Bank, National Association, as administrative agent, Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and SG Americas Securities, LLC (collectively, the “Lenders”). The Senior Credit Facility has a maturity date of February 25, 2018 and up to $250 million in commitments.

The Partnership immediately borrowed $180.8 million under the Senior Credit Facility, of which $99.5 million was paid in connection with the Contribution, $63.0 million was paid in connection with the Redemption, $15 million was used to repay the outstanding balance as of February 27, 2015 under the Partnership’s existing senior secured revolving credit facility and $3.3 million was used to pay fees and expenses associated with the Senior Credit Facility.

The Senior Credit Facility requires that (a) all domestic restricted subsidiaries of the Partnership guarantee the obligations of the Partnership and the subsidiary guarantors under (i) the Senior Credit Facility and other loan documents and (ii) certain hedging agreements and cash management agreements with lenders and affiliates of lenders, and (b) all such obligations be secured by a security interest in substantially all of the assets of the Partnership, including the contributed Legacy System. and the subsidiary guarantors, in each case, subject to certain customary exceptions.

The Senior Credit Facility provides for a $15 million sublimit for letters of credit and a $15 million sublimit for swingline loans. Borrowings under the Credit Agreement bear interest at (a) the LIBOR Rate (as defined in the Senior Credit Facility) plus an applicable margin of 2.75% - 3.75% or (b) the Base Rate (as defined in the Senior Credit Facility) plus an applicable margin of 1.75% - 2.75%, in each case, based on the Consolidated Total Leverage Ratio (as defined in the Senior Credit Facility). Until such time as the Partnership receives gross cash proceeds of not less than $50 million from the consummation of a single issuance of common equity and prepays the loans under the Senior Credit Facility in an amount not less than $50 million (the “Availability Period”), the amount the Partnership may borrow under the Senior Credit Facility is limited to an amount (the “Availability”) equal to the sum of (a) the product of (i) 4.5 and (ii) Eligible Gas Gathering EBITDA (as defined in the Senior Credit Facility); plus (b) the lesser of (i) $15 million and (ii) Eligible Transloading EBITDA (as defined in the Senior Credit Facility). During the Availability Period, the Availability shall be determined periodically in connection with the Partnership’s delivery of annual and quarterly financial statements pursuant to the Senior Credit Facility and upon the occurrence of certain other events described in the Senior Credit Facility.

The Senior Credit Facility contains affirmative and negative covenants customary for credit facilities of its size and nature that, among other things, limit or restrict the ability of the Partnership and its subsidiaries to (a) incur additional debt; (b) grant certain liens; (c) make certain investments; (d) engage in certain mergers or consolidations; (e) dispose of certain assets; (f) enter into certain types of transactions with affiliates; (g) make distributions, with certain exceptions, including the distribution of Available Cash (as defined in the Partnership Agreement) if no default or event of default exists and, during the Availability Period, if an Availability deficiency exists, the aggregate amount of distributions of Available Cash made during such deficiency shall not exceed $10 million (h) enter into certain restrictive agreements or amend certain material agreements and (i) prepay certain debt.

The Senior Credit Facility requires that the Partnership’s ratio of Consolidated Funded Indebtedness (as defined in the Senior Credit Facility) on the date of determination to Adjusted Consolidated EBITDA (as defined in the Senior Credit Facility) for a trailing four fiscal quarter period not exceed 4.50 to 1.00 (or 5.00 to 1.00 for the period commencing on the date that a certain acquisition is consummated through the last day of the second full fiscal quarter following the date of such acquisition). In addition, the Credit Agreement requires the Partnership’s ratio of Adjusted

Consolidated EBITDA for a trailing four fiscal quarter period to Consolidated Interest Expense (as defined in the Senior Credit Facility) for such period to be at least 2.50 to 1.00.

Termination of Existing Omnibus Agreement and Entering into New Omnibus Agreement

In connection with the closing of the Transactions, the Partnership terminated its Omnibus Agreement, dated July 31, 2013 (the “Existing Omnibus Agreement”), by and between NuDevco and its affiliates, the General Partner and the Partnership (together with the General Partner, the “Partnership Parties”). NuDevco and its affiliates released each of the Partnership Parties, and each of the Partnership Parties released NuDevco and its affiliates, from any claims or liabilities arising from or under the terms of the Omnibus Agreement (other than any obligations under the Transaction Agreement).

Also in connection with the closing of the Transactions, the Partnership entered into an omnibus agreement (the "New Omnibus Agreement") with the General Partner and Azure, pursuant to which, among other things:

- Azure will provide corporate, general and administrative services (the "Services") on behalf of the General Partner for the benefit of the Partnership and its subsidiaries;
- The Partnership is obligated to reimburse Azure and its affiliates for costs and expenses incurred by Azure and its affiliates in providing the Services on behalf of the Partnership, including, but not limited to, administrative costs and the compensation costs of the employees of Azure and its affiliates that provide Services to the Partnership;
- The General Partner or Azure may at any time temporarily or permanently exclude any particular Service from the scope of the New Omnibus Agreement upon 90 days' notice;
- The Partnership or Azure may terminate the New Omnibus Agreement in the event that Azure ceases to control the General Partner. Azure may also terminate the New Omnibus Agreement if the General Partner is removed without cause and the units held by the General Partner were not voted in favor of the removal; and
- The Partnership will have a right of first offer on any proposed transfer of any assets owned by Azure or its subsidiaries as of January 14, 2015.

Amendment to Transloading Services Agreements

Upon the closing of the Transactions, the Partnership entered into amendments to its (i) Wildcat Transloading Services Agreement associated with its transloading facility located in Carbon County, Utah, (ii) Big Horn Transloading Services Agreement associated with its transloading facility located in Big Horn County, Wyoming and (iii) Ladder Transloading Services Agreement, all of which are transloading services agreements with AES. The amendments extend the minimum volume commitments associated with these services agreements until February 27, 2020, or an additional five years from the date of the amendment.

MARLIN MIDSTREAM PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

SUPPLEMENTAL QUARTERLY FINANCIAL DATA (unaudited)
Marlin Midstream Partners, LP
Summarized quarterly financial data for the year ended December 31, 2014 is as follows:

	For the year ending December 31, 2014				
in thousands except volume and per unit amounts	Q1	Q2	Q3	Q4	TOTAL
Revenues	$18,818	$22,445	$17,219	$16,746	$75,228
Cost of revenues	4,208	7,240	2,762	3,138	17,348
Gross margin	14,610	15,205	14,457	13,608	57,880
Operating expenses	4,316	4,000	3,637	3,614	15,567
G&A expenses	2,497	2,036	1,729	2,407	8,669
Other operating expenses	2,443	2,577	2,601	2,572	10,193
Operating income	5,354	6,592	6,490	5,015	23,451
Other income(expense)	(155)	(182)	(212)	(217)	(766)
Net income before income taxes	$5,199	$6,410	$6,278	$4,798	$22,685
Net income per limited partner common unit - basic (1)	$0.28	$0.35	$0.33	$0.25	$1.23
Net income per limited subordinated unit - basic (1)	$0.29	$0.36	$0.33	$0.25	$1.22
Net income per limited partner common unit - diluted (1)	$0.28	$0.35	$0.33	$0.25	$1.21
Net income per limited subordinated unit - diluted (1)	$0.29	$0.36	$0.33	$0.25	$1.22
Weighted average limited partner units outstanding - basic	17,601,902	17,602,034	17,673,561	17,703,793	17,626,840
Weighted average limited partner units outstanding - diluted	17,711,652	17,711,652	17,771,140	17,837,813	17,751,279

	For the year ending December 31, 2013				
in thousands except volume and per unit amounts	Q1	Q2	Q3	Q4	TOTAL
Revenues	$7,504	$10,298	$18,950	$16,108	$52,860
Cost of revenues	2,528	2,680	6,479	2,312	13,999
Gross margin	4,976	7,618	12,471	13,796	38,861
Operating expenses	3,896	3,700	4,283	4,012	15,891
G&A expenses	1,411	1,321	2,482	2,672	7,886
Other operating expenses	2,219	2,369	2,349	2,476	9,413
Operating income	(2,550)	228	3,357	4,636	5,671
Other income(expense)	(1,374)	(1,421)	(1,424)	(178)	(4,397)
Net income before income taxes	$(3,924)	$(1,193)	$1,933	$4,458	$1,274
Net income per limited partner unit - basic (1)			$0.16	$0.24	$0.40
Net income per limited partner unit - diluted (1)			$0.15		