Marlin Midstream Partners, LP
Form 10-K
February 27, 2014

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, 2013
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<br>(State or other jurisdiction of<br>incorporation or organization) | 46-2627595<br>(I.R.S. Employer<br>Identification Number) |
| 2105 CityWest Boulevard<br>Suite 100<br>Houston, Texas 77042<br>(832) 200-3702<br>(Address of principal executive offices) | 77042<br>(Zip Code) |

(832) 200-3702
(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 Stock Market LLC |

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 ¨ Smaller reporting company ¨

Accelerated filer ¨ Non-accelerated filer þ
(Do not check if 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 $115,500,000 on December 31, 2013, based on the closing price as reported on NASDAQ. As of June 28, 2013, the last day of the registrant's most recently completed fiscal quarter, the registrant's common units were not publicly traded. The registrant's common units began trading on the NASDAQ on July 30, 2013
There were 17,805,194 common units outstanding as of February 27, 2014.

MARLIN MIDSTREAM PARTNERS, LP
INDEX TO ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2013

## 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.
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;
- 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;
- 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 caused by hurricanes, earthquakes, floods, fires, severe weather, 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;
- 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 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 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.

- 5

# 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 NGL’s to third parties.
NuDevco owns and controls the Partnership’s general partner, Marlin Midstream GP, LLC (our “general partner”). NuDevco is whole 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. Common units held by public security holders represent 38.6% of all of our outstanding limited partner interests, and NuDevco holds 59.4% of all 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 the Partnership’s 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.
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 the Partnership and its subsidiaries.
Available information. We file our annual report 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 2105 CityWest Boulevard, Suite 100, Houston, Texas 77042. Our telephone number is 832-217-1848.

## 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 Crude Oil Logistics Segment.

For additional information relating to our disclosure of revenues, profits and total assets by operating segment, please see Note 9 “Segment Information” to our Consolidated Financial Statements included in this Form 10-K.
Midstream Natural Gas Segment. As of December 31, 2013, our midstream natural gas segment primarily consisted of the following assets: (i) two related natural gas processing facilities located in Panola County, Texas, (ii) a natural gas processing facility located in Tyler County, Texas, (iii) two natural gas gathering systems connected to our Panola County processing facilities, and (iv) two NGL transportation pipelines that connect our Panola County and Tyler County processing facilities 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.
The following table sets forth information about our primary midstream natural gas assets, as of and for the year ended December 31, 2013:

| 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 (1) | Processing | Panola, Texas | | 10,400 | 120 |
| Total Panola | | | N/A | 18,620 | 220 |
| Tyler (2) | 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 (3) | 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 |

(1) Our second facility in Panola County, which we refer to as our Panola 2 processing plant, became fully operational in May 2012.
(2) Our Tyler processing facility includes three cryogenic trains. Our 40 MMcf/d cryogenic train is currently in operation. Our two remaining cryogenic trains, each with an approximate design capacity of 20 MMcf/d, can be made operational with additional capital expenditures.
(3) Our Oak Hill Lateral was completed in March 2013.

Panola County Processing Facilities
Our Panola County processing facilities are situated northeast of the town of Carthage in East Texas on approximately 35 acres. These facilities 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 facilities 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.
The first of our facilities in Panola County, which we refer to as our Panola 1 processing plant, became fully operational in April 2007. Our second facility in Panola County, which we refer to as our Panola 2 processing plant, became fully operational in May 2012. We currently operate our Panola 1 and Panola 2 processing plants as a single integrated facility, with common inlet and outlet points. Our Panola County facilities 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 facilities 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 facilities 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 facilities 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 Facility

Our Tyler County processing facility is situated northeast of the town of Woodville in East Texas on approximately 10 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 facility was constructed in two phases: Phase I became fully operational in April 2006, and Phase II became fully operational in August 2007. This facility includes one cryogenic processing train with a nameplate capacity of 40 MMcf/d, two 20 MMcf/d cryogenic processing trains with an aggregate nameplate capacity of 40 MMcf/d, both of which will require additional capital expenditures to become operational, 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 facility. 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 facility 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 facility 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 facilities and gathers natural gas primarily from delivery points on our gathering systems and interconnecting pipelines in the area. Our sponsor and its affiliates purchased the original Lake Murvaul gathering system, consisting solely of a 12-inch trunk line extending 10.3 miles southwest from the site of our Panola County processing facilities, from CenterPoint Energy in 2004. 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 facilities 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 with less than one half mile of pipeline looping) extending approximately two miles from our Panola County processing facilities 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 facility to an NGL pipeline owned by West Texas LPG Pipeline Limited Partnership for redelivery to the Enterprise fractionator in Mont Belvieu.

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").

We also own and operate a natural gas delivery facility in Maricopa County, Arizona. This facility provides a 1/4 -mile, 2-inch interconnection from El Paso Natural Gas Company to the Ergon Asphalt Products plant boiler inlet. The supply of gas to Ergon is made by an affiliate of Spark Energy, who pays us a fixed fee per MMBtu to provide natural gas delivery services to the Ergon delivery point.

Crude Oil Logistics Segment

As of December 31, 2013, our crude oil 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, and (ii) our Big Horn facility located in Big Horn County, Wyoming, where we currently operate one skid transloader and one ladder 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 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. Each of our skid transloaders was acquired from the manufacturer within the last year 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 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. At our IPO 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. Currently, AES contacts us when they have crude oil that they wish to have transferred from truck to railcar. We then transfer the crude oil from the truck to a railcar or to a third-party tank leased by AES using either a skid transloader or a ladder transloader. At our IPO 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.

Our Fee-Based Commercial Agreements

Prior to the IPO, we 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, 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 that, at the option of AES and subject to the availability of capacity at our Panola facilities, may be increased to 100 MMcf/d. Under our new transloading services agreements, AES pays us a fixed fee per barrel. The 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 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 | 80 MMcf/d |
| Anadarko Tyler County Agreement | October 31, 2015 | Year-to-year | No |
| AES Wildcat Skid Transloading Agreement (1) | Three years | Year-to-year | 7,600 Bbls/d |
| AES Big Horn Skid Transloading Agreement (1) | Three years | Year-to-year | 7,600 Bbls/d |
| AES Master Ladder Transloading Agreement (1) | Three years | Year-to-year | 3,780 Bbls/d |

(1) The AES agreements were entered into between us and AES in conjunction with the closing of the IPO on July 31, 2013. The initial term of these agreements will expire on the third anniversary of the IPO. AES is an affiliate under common control with our sponsor. For additional information relating to our sponsor relationships, please see Items 1 and 2 - "Business and Properties - Sponsor Relationship" included in this Form 10-K.

STRATEGY

Our principal business objectives are to maintain stable cash flows and to increase our quarterly cash distribution per unit over time. We expect to achieve and maintain these objectives by executing the following strategies:

- Focus on Stable, Fee-Based Business. We intend to continue to focus on opportunities to provide fee-based midstream energy services to our customers. Substantially all of our gross margin is supported by minimum volume commitments that promote stable cash flows.
- Pursue Strategic and Accretive Acquisitions. We plan to pursue accretive acquisitions of midstream natural gas and crude oil logistics assets from our sponsor and, to a lesser extent, third parties that will provide attractive returns and are complementary to our existing assets in existing or new geographic areas or business lines.
- Focus on Underserved Producing Regions with Attractive Characteristics. We focus on growing our businesses in regions that we believe are underserved by our competitors and will require midstream natural gas or crude oil logistics assets to handle existing and anticipated liquids-rich natural gas and crude oil production.
- Maintain Financial Flexibility and Conservative Leverages. We maintain a conservative capital structure with ample liquidity that will enable us to pursue strategic acquisitions and organic expansion opportunities.

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 assets are located in areas that we believe provide opportunities to access increasing liquids-rich natural gas and crude oil supplies from existing and new customers.
- Modern and Efficient Assets. All of our 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.
-

- Relationship with our Sponsor. We believe that our relationship with our sponsor will provide us with opportunities to acquire additional midstream natural gas and crude oil logistics 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.
- 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.

- 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.
- Entrepreneurial and Experienced Energy Industry Management Team. Our executive management team has an average of over 24 years of experience in the energy industry and has demonstrated a successful track record of growing businesses and of identifying and developing midstream energy opportunities.

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 Form 10-K.

SPONSOR RELATIONSHIP

Our sponsor, NuDevco Partners, LLC, is the ultimate parent company of Spark Energy. NuDevco is wholly owned by W. Keith Maxwell III, who founded the predecessor of Spark Energy in 1999 and grew the company from a Houston-based regional retail natural gas company to a multi-state certified retail electricity and natural gas supplier operating in 17 states and 45 local markets. In addition to Spark Energy, NuDevco also owns NuDevco Midstream Development and indirectly owns AES. NuDevco Midstream Development's primary strategy is to purchase and develop midstream natural gas and crude oil logistics assets. AES primarily purchases, sells and markets natural gas, NGLs and crude oil. At our IPO date of July 31, 2013, we entered into fee-based commercial agreements with AES with minimum volume commitments and annual inflation adjustments under which we will not be subject to direct commodity price risk. Through its gathering and processing agreement with us, AES will also provide gathering and processing services to its natural gas customers in connection with its producer services business.

NuDevco Midstream Development and AES work together to seek opportunities to provide value-added midstream services to producers of crude oil, natural gas and NGLs. In addition, AES is one of our principal customers. We believe that our relationship with our sponsor and its affiliates provides us with significant potential long-term growth opportunities through the development and acquisition of additional midstream energy assets, as well as opportunities to minimize our direct commodity price exposure through fee-based midstream service agreements with AES.

Under the terms of the omnibus agreement, NuDevco Midstream Development grants us a right of first offer on certain midstream energy assets, including transloaders, storage tanks, railcars, tanker trucks and gas processing and treating assets, during the five-year period following the IPO on July 31, 2013. In addition, in connection with our acquisition of any transloaders, storage tanks, railcars or tanker trucks, AES is obligated to negotiate in good faith a service agreement with us covering such assets to the extent such assets are not subject to an existing service agreement at the time of acquisition. However, we are under no obligation to purchase any assets from our sponsor or enter into any service agreements, and our sponsor has no obligation to accept any offer we may make for such assets or to enter into any such service agreements. For additional information regarding these agreements and our relationship with our sponsor, please see Item 13 - "Certain Relationships and Related Party Transactions" included in this Form 10-K.

As of December 31, 2013, NuDevco Midstream and Affiliates held 10,574,090 of our common units, representing a 59.4% limited partner interest in us, and, through its ownership of our general partner, indirectly held 356,104 general partner units representing a 2.0% general partner interest in us and 100% of our incentive distribution rights ("IDRs"). As of December 31, 2013, the public held 6,875,000 common units, representing a 38.6% limited partner interest in us.

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 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.

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 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. 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, 2013, Anadarko, Enterprise 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. At the closing of our IPO, AES contracted for 100% of the capacity at our Wildcat and Big Horn 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. 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 facilities 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 Pipeline Safety Improvement Act of 2002, as amended by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (“PIPES Act”), the Accountable Pipeline Safety and Partnership Act of 1996 (“APSA”) 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 gas transmission pipelines that, in the event of a failure, could affect “high consequence areas.” “High consequence areas” are currently defined as areas with specified population densities, buildings containing populations of limited mobility and areas where people gather that are located along the route of a pipeline. Similar rules are also in place for operators of 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 rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. On September 25, 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 and recently, in August 2013, sought public comments on whether this expansion of high consequence areas would mitigate the need for class location requirements that have been used in the past primarily to differentiate risk along a pipeline. In May 2012, PHMSA issued an Advisory Bulletin stating that records used to establish maximum allowable pipeline operating pressures must be traceable, verifiable and complete. Locating our records and, in the absence of any records, verifying maximum pressures through physical testing, could increase our costs or result in reductions of allowable operating pressures.

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 years 2013 through 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:

- 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;
- 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
- 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 material compliance with applicable federal, state, and local laws and regulations. We expect any legislative or regulatory changes to 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 new laws or rules or the 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 an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate;
- 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 during permit reviews;
- 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 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 do not believe that compliance with federal, state or local environmental 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 or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions will not cause us to incur significant costs.

Below is a discussion of the material environmental laws and regulations, as amended from time to time, that relate to our business. We believe that we are in substantial compliance with all of these environmental laws and regulations.

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 solid and hazardous wastes. 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 found 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. We handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations 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 strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. We generate minimal amounts of hazardous wastes; however, it is possible that these 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 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 believe that we are in substantial compliance with these requirements. 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. We believe, however, that our operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to us than to any other similarly situated companies.

For example, in 2012, the EPA published final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. This new rule addresses emissions of various pollutants frequently associated with oil and natural gas production and processing activities. For new or reworked hydraulically-fractured wells, the final rule requires controlling emissions through flaring until 2015, when the rule requires the use of reduced emission, or "green," completions. The rule also establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment. This rule may require a number of modifications to our and our customers' operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs, including increased capital expenditures and operating costs, for us and our customers which may adversely impact our business.

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 and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. Spill prevention, control and countermeasure ("SPCC") standards under federal law requires the development and implementation of SPCC plans, including appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. To be in compliance, the facility's SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intra-facility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC plan and train personnel in its execution. 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. These permits may require us to monitor and sample the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. We believe that compliance with existing permits and compliance with foreseeable new permit requirements will not have a material adverse effect on our financial condition, results of operations or cash flows.

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 associated 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. We believe that we are in substantial compliance with the applicable requirements of the Clean Water Act, OPA and analogous state laws, and that the requirements imposed by these laws and implementing regulations will not be any more burdensome to us than to any other similarly situated companies.

Hydraulic Fracturing

A portion 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, but the EPA has asserted limited regulatory authority over hydraulic fracturing, and has indicated it may seek to further expand its regulation of hydraulic fracturing. Also, the Bureau of Land Management has proposed regulations applicable to hydraulic fracturing conducted on federal and Indian oil and gas leases. 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 and Wyoming, where we conduct operations, 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. 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, the EPA and the U.S. Department of Energy, 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 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

In December 2009, the EPA published 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, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under the Clean Air Act that, among other things, establish GHG emission limits from motor vehicles as well as establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases by the EPA on a case-by-case basis. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States on an annual basis. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring and reporting activities are in substantial compliance with applicable reporting obligations.

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 equipment and operations could require us 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. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide. 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 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, on November 20, 2007, further 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

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. As of December 31, 2013, our general partner and its affiliates have approximately 65 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 our IPO, employees of Marlin Midstream were transferred to NuDevco Midstream Development, a wholly owned subsidiary of our sponsor. Under our omnibus agreement, NuDevco indemnifies us for any liabilities incurred by us in connection with the transfer of such employees.

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, 2013. Although we have gathering and processing agreements with both of these customers, these agreements have remaining terms ranging from two to six 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.

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 $6.2 million per quarter, or $24.9 million per year, based on the number of common and subordinated units and the general partner interest to be outstanding as of December 13, 2013. 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;
- 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;
- damage to pipelines, facilities, plants, related equipment and surrounding properties caused by hurricanes, earthquakes, floods, fires, severe weather, 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; 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 three-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 will enter into with AES at the closing of this offering.

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 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.

- 24

We are a relatively small enterprise. As a result, operational, financial and other events in the ordinary course of business could disproportionately affect us, and our ability to grow our business could be significantly limited.
We will be smaller than many other publicly traded partnerships in our industry for the foreseeable future, not only in terms of market capitalization but also in terms of managerial, operational and financial resources. Consequently, an operational incident, customer loss or other event that would not significantly impact the business and operations of larger publicly traded partnerships in our industry may have a material adverse impact on our business and results of operations. Furthermore, acquisitions and other growth projects may place a significant strain on our management resources. As a result, our ability to execute our growth strategy and to integrate acquisitions and expansion projects successfully into our existing operations could be significantly limited.
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 crude oil 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;

- 25

- 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.

Certain of our gathering and processing agreements contain provisions that can reduce the cash flow stability that the agreements were designed to achieve.

Our fee-based gathering and processing agreements are generally designed to generate stable cash flows to us over the life of the contract term while also minimizing our direct commodity price risk. However, our gathering and processing agreements with Anadarko at our Panola County processing facilities contain provisions that can reduce the cash flow stability that these agreements were designed to achieve. The primary mechanism on which we rely to generate our stable cash flows under our agreements with Anadarko at our Panola County processing facilities is a minimum volume commitment. If Anadarko's actual throughput volumes are less than its minimum volume commitment for a given year, it must make a shortfall payment to us at the end of that year. The amount of the shortfall payment is based on the difference between the actual throughput volume for the year and the minimum volume commitment over that year, multiplied by the applicable gathering and processing fees. To the extent that Anadarko's actual throughput volumes exceed its minimum volume commitment for the applicable period, the agreements contain provisions that allow Anadarko to use that surplus volume as a credit against future shortfall payments in subsequent periods during the primary term, and during the renewal terms for certain of the agreements.

Because Anadarko has a crediting mechanism that allows it to build a "bank" of credits (to the extent its throughput volumes exceed its minimum volume commitment for a given year) that it can utilize in the future to reduce shortfall payments owed in future years, we may receive lower gathering and processing fees in a particular contract year than we would otherwise be entitled to receive under Anadarko's minimum volume commitment.

The combined effect of the minimum volume commitment and the ability to build a surplus credit could result in our receiving no revenues or cash flows from Anadarko in a future period because Anadarko could cease delivering throughput volumes at a time when their respective year-end minimum volume commitment has been satisfied with previous throughput volume deliveries. Similarly, because these minimum volume commitments are assessed on an annual basis, we may not receive revenues or cash flows during a given sub-period if Anadarko anticipates satisfying its minimum volume commitment in a later sub-period during the same year.

If either of these circumstances were to occur, it could materially and adversely affect our results of operations, financial condition and cash flows and our ability to make 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 incentive distribution rights 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.

Lower natural gas prices or NGL prices over the long-term could result in a decline in the production of natural gas and result in reduced throughput on our midstream natural gas systems. 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.

A decline in natural gas and NGL prices would have a negative impact on exploration, development and production activity in our areas of operation and result in a decrease in throughput on our midstream natural gas systems from our producer customers. 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. If natural gas prices or NGL prices remain depressed or decrease further, it could cause sustained reductions in exploration or production activity in our areas of operation, reduce the economic benefit of recovering NGLs from the natural gas stream and result in a further reduction in throughput on our midstream natural gas systems. Also, 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 NuDevco Midstream Development’s midstream energy assets is subject to risks and uncertainty, and ultimately we may not acquire any of those assets.

Our omnibus agreement provides us with a right of first offer on certain of NuDevco Midstream Development's midstream energy assets during the five-year period following our initial public offering. The consummation and timing of any acquisition by us of the assets covered by our right to first offer will depend upon, among other things, our ability to reach an agreement with NuDevco Midstream Development on price and other terms, our ability to reach an agreement with AES on the services to be provided by us utilizing any acquired assets, where applicable, and our ability to obtain financing on acceptable terms. Accordingly, 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 NuDevco 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 NuDevco Midstream Development 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 crude oil 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 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 from third parties, 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;
- an inability to integrate successfully the assets or businesses we acquire, particularly given the relatively small size of our management team;
- 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.
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 in which 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 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 substantially while 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 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 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 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 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 pipelines located where a leak or rupture could harm “high consequence areas,” including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The regulations require operators, 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 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 2014 and 2015 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL 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. 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. PHMSA continues to evaluate the public comments received with respect to more stringent integrity management programs and recently, pursuant to one of the requirements in the 2011 Pipeline Safety Act, published a proposed rulemaking on August 1, 2013, seeking comments on whether an expansion of high consequence areas would mitigate the need for class location requirements that have been used in the past primarily to differentiate risk along a pipeline.

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 natural gas and NGLs transportation pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, and testing to confirm that the material strength of certain pipelines are above 30% of specified minimum yield strength.

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 or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto 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 be significant and have a material adverse effect on our results of operations or financial position. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations. We cannot predict with any certainty at this time the terms of new laws, rules or regulatory interpretations, or the costs of compliance associated with such requirements.
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. Examples of these laws include:

- the CAA and analogous state laws that impose obligations related to air emissions, including, in the case of the CAA, GHG emissions and regulations affecting reciprocating engines subject to Maximum Achievable Control Technology standards;
- the CERCLA, and analogous state laws that regulate the cleanup of hazardous substances that may be or have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;
- the Clean Water Act, and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;
- the OPA, and analogous state laws that establish strict liability for removal costs and damages arising from an oil release into waters of the United States;
- the RCRA, and analogous state laws that impose requirements for the storage, treatment and disposal of non-hazardous and hazardous waste from our facilities;
- the ESA, which restricts activities that may affect endangered or threatened species or their habitats; and
- the Toxic Substances Control Act, and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities.

These 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. 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 liability 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 and NGL transportation activities for a number of years. Private parties, including the owners of the properties through which our gathering or transportation systems pass 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. 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.

Our operations may impact the environment or cause environmental contamination, which could result in material liabilities to us.

Our operations use hazardous substances, generate limited quantities of hazardous wastes and may affect runoff or drainage water. In the event of environmental contamination or a release of regulated materials, we could become subject to claims for toxic torts, natural resource damages and other damages and for the investigation and clean-up of soil, surface water, groundwater, and other media. Such claims may arise out of conditions at sites that we currently own or operate. Our liability for such claims may be joint and several, so that we may be held responsible for more than our share of the contamination or other damages, or even for the entire share. These and other impacts that our operations may have on the environment, as well as exposures to hazardous substances or wastes associated with our operations, could result in costs and liabilities that could have a material adverse effect on us. 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.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could materially and adversely impact our revenues by decreasing the volumes of natural gas and NGLs that we gather and process or crude oil that we transport.

A portion of our customers’ crude 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, but the EPA has asserted limited regulatory authority over hydraulic fracturing, and has indicated it may seek to further expand its regulation of hydraulic fracturing. Also, the Bureau of Land Management has proposed regulations applicable to hydraulic fracturing conducted on federal and Indian oil and gas leases. 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 and Wyoming, where we conduct operations, 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. 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, the EPA and the U.S. Department of Energy, 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.

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 and Big Horn 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 rail siding lease at our Wildcat facility with a term that expires August 20, 2014, and a rail siding lease and service agreement at our Big Horn facility with an initial term that expires March 31, 2014.

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.

In December 2009, the EPA published its findings that emissions of GHG present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has adopted rules under the CAA that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources, 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 reporting of GHG emissions from specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States on an annual basis, which include certain of our operations. 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 equipment and operations could require us 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. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide.

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, unlike other public companies, 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.

If we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.

We are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes Oxley Act of 2002, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. We are required to comply with the SEC's rules implementing Sections 302 and 404 of the Sarbanes Oxley Act of 2002, which require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Though we are required to disclose material changes made to our internal controls and procedures on a quarterly basis, we are not required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 until the filing of our annual report for the year ended December 31, 2014. Furthermore, while we generally must comply with Section 404 of the Sarbanes Oxley Act of 2002 for our fiscal year ended December 31, 2013, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our annual report for the fiscal year ending December 31, 2018. Once it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed, operated or reviewed.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a publicly traded partnership. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results will be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

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.

At the closing of our initial public offering on July 31, 2013, we entered into a $50.0 million senior secured revolving credit facility. Our revolving credit facility limits our ability to, among other things:

- incur certain additional indebtedness;
- grant certain liens;
- engage in certain asset dispositions;
- merge or consolidate;
- make certain payments, distributions, investments, acquisitions or loans;
- enter into transactions with affiliates;
- make certain changes in our lines of business or accounting practices, except as required by GAAP or its successor;
- store inventory in certain locations;
- place certain amounts of cash in accounts not subject to control agreements;
- amend or modify certain agreements and documents;
- incur certain capital expenditures;
- engage in certain prohibited transactions;
- enter into burdensome agreements; and
- act as a transmitting utility or a utility.

Our 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. Our ability to meet those financial ratios and conditions can be affected by events beyond our control, and we cannot assure that we will meet those ratios and conditions.

The provisions of our revolving credit facility 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 revolving credit facility 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.

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

As of December 31, 2013, we had unused capacity under our revolving credit facility of $46.0 million and outstanding borrowings of $4.0 million. We have the ability to incur additional debt under our revolving credit facility. Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flows required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt 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.

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. As with other yield-oriented securities, our unit price is impacted by our level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price, 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 W. Keith Maxwell III. The loss of Mr. Maxwell 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. Given our small size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives and key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and key personnel could adversely affect our business, financial condition and results of operations.

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

NuDevco owns and controls our general partner, which has 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 NuDevco’s interests to the detriment of us and our unitholders.

NuDevco indirectly owns and controls our general partner and appoints all of the officers and directors of our general partner, some of whom are also officers of NuDevco. W. Keith Maxwell III, the Chairman of the Board of Directors of our general partner, is the sole owner of NuDevco, which in turn controls AES, one of our principal customers. 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 interests of NuDevco, AES and their respective 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, such as NuDevco, AES and their respective affiliates, 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 NuDevco in respect of the incentive distribution rights.
- 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.
- NuDevco may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our sponsor’s incentive distribution rights 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.

NuDevco and its affiliates, including AES, are not limited in their ability to compete with us and, other than as provided in the omnibus agreement that we have entered into with NuDevco, NuDevco Midstream Development and our general partner at the close of our initial public offering, 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.

NuDevco 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, NuDevco 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 obligations as set forth in the omnibus agreement that we entered into with NuDevco, NuDevco Midstream Development and our general partner at the closing of our initial public offering. Moreover, except for the obligations set forth in the omnibus agreement, neither NuDevco 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
- 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.

- 40

NuDevco, as the owner of all of our incentive distribution rights, may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to its incentive distribution rights 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.

NuDevco, as the owner of all of our incentive distribution rights, 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 NuDevco, 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.

We anticipate that NuDevco 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 NuDevco could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when NuDevco expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, NuDevco 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 NuDevco 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 NuDevco in connection with resetting the target distribution levels related to NuDevco’s incentive distribution rights.

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 NuDevco. 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 because our general partner and its affiliates own sufficient units to be able to prevent its removal. 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 64.2% of our outstanding common and subordinated units. 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 further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their 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 NuDevco 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.

The incentive distribution rights indirectly held by NuDevco may be transferred to a third party without unitholder consent.

NuDevco, as the indirect owner of the incentive distribution rights, may transfer its incentive distribution rights to a third party at any time without the consent of our unitholders. If NuDevco transfers the incentive distribution rights to a third party, NuDevco and its affiliates may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of its incentive distribution rights. For example, a transfer of incentive distribution rights by NuDevco could reduce the likelihood of NuDevco accepting offers made by us relating to assets subject to the right of first offer contained in our omnibus agreement or renewing contractual arrangements with us in the future, as NuDevco and its affiliates would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

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 NuDevco:

- our business will no longer be solely managed by our general partner's current owner, NuDevco;
- 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.

We have 8,724,545 common units and 8,724,545 subordinated units outstanding and NuDevco holds an aggregate of 1,849,545 common units and 8,724,545 subordinated units. 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.

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

- 42

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 21.2% 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 60.6% of our outstanding common units.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect certain publicly traded partnerships. We are unable to predict whether any such proposals will ultimately be enacted. However, it is possible that a change in law could affect us and may be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

Our unitholders' share of our income will be taxable to them for U.S. federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income which could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes on its share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability resulting 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 our unitholders sell common units, they will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than its tax basis in those common units, even if the price the unitholder receives is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale of a unitholder's common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units 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 (known as 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 federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a 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.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from a unitholder's 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 will 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 will 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 will adopt certain valuation methodologies and monthly conventions for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction between our general partner, our unitholders and the holder of our incentive distribution rights. The IRS may challenge this treatment, which could adversely affect the value of the common units.

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

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

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

We will be considered to have technically terminated 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 will initially own property or conduct business in Texas, Utah, Arizona, Louisiana and Wyoming. Utah, Arizona and Louisiana currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may own property or conduct business in additional states that impose a personal income tax. 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 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.

| 2013 | Third Quarter (1) | Fourth Quarter |
|---|---|---|
| High Price | $ 20.25 | $ 19.25 |
| Low Price | $ 17.45 | $ 15.93 |
| Distribution per common unit (2) | $ 0.23 | $ 0.35 |

(1) From August 8, 2013, the date our common units began trading on the NASDAQ Stock Market LLC, 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 from the IPO date of July 31, 2013 through September 30, 2013.

As of January 31, 2014, there were approximately 27 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 356,104 general partner units for which there is no established public trading market. All general 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 the Partnership’s 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) 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.

SELECTED INFORMATION FROM THE PARTNERSHIP AGREEMENT

Distributable cash and distributions. The partnership agreement requires the Partnership 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, beginning with the quarter ending September 30, 2013.

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 a 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 were declared for the period from August 1, 2013 to December 31, 2013:

| In Thousands, except per-unit amounts | | Total Quarterly | Total | Date of |
|---|---|---|---|---|
| Quarter ended: | | Distribution per Unit | Distribution | Distribution |
| December 31, 2013 | | $0.35 | $6,341,018 | February 3, 2014 |
| September 30, 2013 | (1) | $0.23 | $4,166,955 | November 4, 2013 |
| June 30, 2013 | (2) | $— | $— | — |

(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) No distributions were declared for the quarter ended June 30, 2013. This quarter was included in the results reported in the report on Form 10-Q for the second quarter ended June 30, 2013; however, this quarter was prior to the completion of the IPO.

Item 6. Selected Financial Data
The following table shows our selected financial and operating data, which are derived from our consolidated 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 sponsor, NuDevco Partners, LLC ("NuDevco"), is the ultimate parent company of Spark Energy Ventures, LLC ("SEV"). NuDevco also owns NuDevco Midstream Development, LLC ("NuDevco Midstream") and Associated Energy Services, LP ("AES"). In connection with the offering, 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 2,474,545 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.

We also transferred to affiliates of our 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 2013 | 2012 | 2011 |
|---|---|---|---|
| Statement of Operations Data (for the year ended): | | | |
| Total Revenues | $52,860 | $51,049 | $65,818 |
| Total operating expenses | 47,189 | 49,499 | 51,453 |
| Operating income | 5,671 | 1,550 | 14,365 |
| Interest income (expense), net | (4,349) | (4,927) | (3,733) |
| Other income (expense), net | (48) | (828) | (2,156) |
| Texas margin tax expense | (88) | (101) | 65 |
| Net income (loss) | $1,186 | $(4,306) | $8,541 |
| | | | |
| Key Performance Measures (for the year ended): | | | |
| Gross margin (1) | $38,861 | $30,026 | $36,962 |
| Adjusted EBITDA (1) | $16,880 | $9,239 | $19,730 |
| Distributable cash flow (1) (2) | $12,982 | n/a | n/a |
| | | | |
| Net income per unit - basic | $0.40 | | |
| Net income per unit - diluted | $0.39 | | |
| Net income per subordinated unit - basic | $0.40 | | |
| Net income per subordinated unit - diluted | $0.40 | | |
| Distributions declared per unit (4) | $0.58 | | |
| | | | |
| Balance Sheet Data (as of the year ended December 31) | | | |
| Net property, plant and equipment | $162,548 | $165,139 | |
| Total assets | $174,142 | $180,796 | |
| Total liabilities | $13,592 | $148,517 | |
| Total equity and partners' capital | $160,550 | $32,279 | |
| | | | |
| Cash Flow Data (for the year ended): | | | |
| Net cash flows provided by (used in): | | | |
| Operating activities | $9,176 | $11,214 | $16,102 |
| Investing activities | $(12,710) | $(12,445) | $(25,658) |
| Financing activities | $1,136 | $6,355 | $8,097 |
| | | | |
| Operating data (for the year ended): | | | |
| Gas volumes (MMcf/d) (3) | 219 | | |
| Transloading volumes (Bbls/d)(3) | 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 Form 10-K.
(2) We will distribute available cash within 45 days after the end of the quarter, beginning with the quarter ended September 30, 2013. For the three months ended September 30, 2013, distributable cash is prorated from our IPO on July 31, 2013 through September 30, 2013.
(3) Volumes reflect the minimum volume commitment under our fee-based contracts or actual throughput, whichever is greater, for the post-IPO period.

(4) Distributions declared per unit include the third quarter 2013 distribution of $0.23 per unit declared October 2013, and the fourth quarter 2013 distribution of $0.35 per unit declared January 2014. For additional information, please see Part II, "Partnership Agreement" included in this Form 10-K.

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 the Partnership 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

Our primary midstream natural gas assets currently consist of (i) two related natural gas processing facilities located in Panola County, Texas with an approximate design capacity of 220 MMcf/d, (ii) a natural gas processing facility 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 facilities 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 approximate design capacity of 20,000 Bbls/d that connect our Panola County and Tyler County processing facilities 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.

Crude Oil Logistics

Our crude oil logistics assets currently consist of two crude oil transloading facilities: (i) our Wildcat facility located in Carbon County, Utah, where we currently operate one skid transloader and two ladder transloaders, and (ii) our Big Horn facility located in Big Horn County, Wyoming, where we currently operate one skid transloader and one ladder 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 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.

General Trends and Outlook

In 2014, our strategic objectives will continue to be focused on maintaining stable distributable cash flows from our existing assets and executing on growth opportunities to increase our long-term distributable cash flows. 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 partnership with NuDevco Midstream Partners LP, 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 during the year ended December 31, 2013 include the following:

- In connection with our IPO on July 31, 2013, we issued 6,875,000 common units, representing a 38.6% limited partner interest, to the public for $20.00 per common unit. Net proceeds of $125.3 million, after underwriting discounts, structuring fees, and other direct IPO costs, were used to repay the existing credit facility of $121.9 million, outstanding amounts on the revolving credit facility of approximately $10.0 million, and settling the interest rate swap liability of approximately $0.1 million.
- In connection with our IPO on July 31, 2013, we entered into a new $50.0 million senior secured revolving credit facility, which matures on July 31, 2017.

- 52

- We declared and paid a prorated cash distribution for the third quarter of 2013 in the amount of $0.23 per unit and declared a cash distribution for the fourth quarter of 2013 in the amount of $0.35 per unit.
- Following the closing of the IPO, 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.
- We entered into transloading services agreements with AES, each with three year terms, minimum volume commitments and annual inflation adjustments.

Significant operational highlights during the year ended December 31, 2013 included the following:

- Our crude oil logistics assets became operational in 2013. Following the closing of the IPO, our crude oil logistics revenues are generated under transloading services agreements that we entered into with AES.
- We completed construction of our Oak Hill Lateral gathering line and installed molecular sieves at our Panola 1 processing facility.

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. Our sponsor, NuDevco Partners, LLC ("NuDevco"), is the ultimate parent company of Spark Energy Ventures, LLC ("SEV"). NuDevco also owns NuDevco Midstream Development, LLC ("NuDevco Midstream") and Associated Energy Services, LP ("AES"). Following the closing of the offering, we entered into fee-based commercial agreements with AES, substantially all of which include minimum volume commitments and annual inflation adjustments. In connection with the offering, 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 2,474,545 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.

We also transferred to affiliates of our 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.

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 was as follows:

| | 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 | % |

- 53

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.

Volumes - We view throughput and storage volumes for our gathering and processing and our crude oil logistics segment as important factors affecting our profitability. We gather and transport the natural gas and NGLs under fee-based transportation contracts. Revenue from these contracts is derived by applying the rates stipulated to the volumes transported. Pipeline throughput volumes from existing wells connected to our pipelines will naturally decline over time as wells deplete. Accordingly, to maintain or to increase throughput levels on these pipelines and the utilization rate of our natural gas processing plants, we must continually obtain new supplies of natural gas and NGLs. Our ability to maintain existing supplies of natural gas and NGLs and obtain new supplies are impacted by: (1) the level of workovers or recompletions of existing connected wells and successful drilling activity in areas currently dedicated to our pipelines; and (2) our ability to compete for volumes from successful new wells in other areas. The throughput volumes of NGLs and gas on our pipelines are substantially dependent upon the quantities of NGLs and gas produced at our processing plants. We regularly monitor producer activity in the areas we serve and in which our pipelines are located, and pursue opportunities to connect new supply to these pipelines. d.

| In Thousands, except volume data | Years Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Gross Margin | $38,861 | $30,026 | $36,962 |
| Gas volumes (MMcf/d) (2) | 219 | | |
| Transloading volumes (Bbls/d) (2) | 18,980 | | |
| Adjusted EBITDA | $16,880 | $9,239 | $19,730 |
| Distributable Cash Flow (1) | $12,982 | n/a | n/a |

(1) We will distribute available cash within 45 days after the end of the quarter, beginning with the quarter ending September 30, 2013. For the three months ended September 30, 2013, distributable cash is prorated from our IPO on July 31, 2013 through September 30, 2013.

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

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 represents our profitability with minimal exposure to commodity price fluctuations, which we believe are not significant components of our operations.

Gross margin is calculated as follows:

| In Thousands | Years Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Total operating income | $5,671 | $1,550 | $14,365 |
| Operation and maintenance | 12,401 | 15,035 | 12,031 |
| Operation and maintenance-affiliates | 3,490 | 793 | 327 |
| General and administrative | 3,699 | 3,045 | 3,260 |
| General and administrative-affiliates | 4,187 | 1,021 | 907 |
| Property and other taxes | 1,216 | 893 | 490 |
| Depreciation expense | 8,197 | 7,689 | 5,365 |
| Loss on disposals of equipment | — | — | 217 |
| Gross Margin | $38,861 | $30,026 | $36,962 |

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, under 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, Texas margin tax, 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, after the closing of the IPO we compute and present this measure, 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 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.

Our partnership agreement requires that, within 45 days after the end of each quarter, beginning with the quarter ended September 30, 2013, we distribute all of our available cash to unitholders of record on the applicable record date. Our cash distribution for the period from the completion of the IPO through September 30, 2013 was adjusted based on the actual length of the period. For the three months ended September 30, 2013, a distribution of $0.23 per unit was declared on October 18, 2013 and paid on November 4, 2013 to unitholders of record as of October 29, 2013. For the three months ending December 31, 2013, a distribution of $0.35 per unit was declared on January 21, 2014 and paid on February 7, 2014 to unitholders of record as of February 3, 2014.

Adjusted EBITDA is calculated as follows:

| In Thousands | Years Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Net income (loss) | $1,186 | $(4,306) | $8,541 |
| Interest expense, net of amounts capitalized | 4,349 | 4,927 | 3,733 |
| Interest and other income | — | (23) | (20) |
| Texas margin tax expense | 88 | 101 | (65) |
| Equity based compensation | 3,012 | — | — |
| Loss on interest rate swap | 48 | 851 | 2,176 |
| Depreciation expense | 8,197 | 7,689 | 5,365 |
| Adjusted EBITDA | $16,880 | $9,239 | $19,730 |

Distributable cash flow subsequent to the IPO is calculated as follows:

Distributable cash flow for the period from July 31, 2013 to December 31, 2013:

| In Thousands | |
|---|---|
| Net income post IPO | $7,190 |
| Add: | |
| Equity based compensation | 3,012 |
| Interest expense, net of amounts capitalized | 352 |
| Depreciation expense | 3,425 |
| Texas margin tax | 60 |
| Adjusted earnings | 14,039 |
| Less: | |
| Maintenance capital expenditures | (782) |
| Cash interest expense | (215) |
| Texas margin tax | (60) |
| Distributable cash flow | $12,982 |

Note Regarding Non-GAAP Financial Measures

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.

Gross margin is a primary performance measure used by our management. We define gross margin as revenues less cost of revenues. Gross margin represents our profitability without regard to commodity sales and purchases, which we believe are not significant components of our operations. 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, state franchise tax, depreciation expense and any gain/loss from interest rate derivatives. Adjusted EBITDA and distributable cash flow are non-GAAP supplemental financial measures that management and external users of our 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 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 our IPO.

- Gathering and Processing Agreements
- Until 2011, our gathering and processing agreements with third parties and our affiliates were primarily keep-whole contracts. Under these contracts, 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. The cost of these “replacement” natural gas volumes was recorded in our cost of revenues. Beginning in late 2011, we contracted with Anadarko and other third party producers at our Panola County processing facilities for significant volumes under a fee-based processing model. A substantial majority of these agreements provide for minimum volume commitments.
- 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 is substantially offset by a corresponding cost of revenue that is recorded when we compensate the customer for its contractual share of the NGLs.
- Following the closing of the IPO, 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.

- Transloading Services Agreements

- Following the closing of the IPO, our crude oil logistics revenues are generated under transloading services agreements that we entered into with AES at the closing of 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.

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 NuDevco. As a result, following the closing of the IPO, we reimburse NuDevco 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 administrative expenses will decrease, compared to historical amounts.

Our historical general and administrative expenses included certain expenses allocated by affiliates of NuDevco 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. Following the closing of the IPO, affiliates of NuDevco will continue to charge us a combination of direct and allocated monthly expenses related to the management and operation of our midstream natural gas and crude oil logistics businesses, and will also charge us an annual fee, initially in the amount of $0.6 million, for executive management services.

In addition, we expect our general and administrative expenses will increase due to the costs of operating as a publicly traded partnership, including costs associated with ongoing SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley compliance expenses, expenses associated with listing on NASDAQ, independent auditor fees, legal fees, investor relations expenses, registrar and transfer agent fees, director and officer insurance expenses and director compensation expenses.

Financing

There are differences in the way we finance our operations now as compared to the way we financed our operations on a historical basis. Historically, our operations were financed by cash generated from operations, equity investments by our sole member and borrowings under our existing 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 new $50.0 million senior secured revolving credit facility. Approximately $4.0 million was outstanding under our new senior secured revolving credit facility as of December 31, 2013 and $126.5 million was outstanding under our previous credit facility as of December 31, 2012. Following the closing of the IPO, we intend to make minimum cash distributions to our unitholders at an initial distribution rate of $0.35 per unit per quarter ($1.40 per unit on an annualized basis). 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 new revolving credit facility and future issuances of equity and debt securities.

RESULTS OF OPERATIONS

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% |
| Texas margin tax expense | 88 | 101 | (13) | (12.9)% |
| Net income (loss) | 1,186 | (4,306) | 5,492 | (127.5)% |
| | | | | |
| Key performance metrics: | | | | |
| Gross margin | 38,861 | 30,026 | 8,835 | 29.4% |
| Adjusted EBITDA | 16,880 | 9,239 | 7,641 | 82.7% |
| | | | | |
| Volumes: | | | | |
| Processing Facilities (MMcf/d) (1) | 219 | | | |
| Transloading Facilities (Bbls/d) (1) | 18,980 | | | |

(1) 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

- 58

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 crude oil 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 a subsidiary of SEV 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, at the closing of our IPO, 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 crude oil 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.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011
The following table presents selected financial data for each of the years ended December 31, 2011 and 2012.

| In Thousands | Years ended December 31, | | | |
|---|---|---|---|---|
| | 2012 | 2011 | Change | % Change |
| REVENUES: | | | | |
| Natural gas, NGLs and condensate revenue | 34,708 | 55,558 | (20,850) | (37.5)% |
| Gathering, processing, transloading and other revenue | 16,341 | 10,260 | 6,081 | 59.3 % |
| Total Revenues | 51,049 | 65,818 | (14,769) | (22.4)% |
| OPERATING EXPENSES: | | | | |
| Cost of natural gas, NGLs and condensate revenue | 21,023 | 28,856 | (7,833) | (27.1)% |
| Operation and maintenance | 15,828 | 12,358 | 3,470 | 28.1 % |
| General and administrative | 4,066 | 4,167 | (101) | (2.4)% |
| Property tax expense | 893 | 490 | 403 | 82.2 % |
| Depreciation expense | 7,689 | 5,365 | 2,324 | 43.3 % |
| Loss on disposals of equipment | — | 217 | (217) | (100.0)% |
| Total operating expenses | 49,499 | 51,453 | (1,954) | (3.8)% |
| Operating income | 1,550 | 14,365 | (12,815) | (89.2)% |
| Interest expense, net of amounts capitalized | (4,927) | (3,733) | (1,194) | 32.0 % |
| Interest and other income | 23 | 20 | 3 | 15.0 % |
| Loss on interest rate swap | (851) | (2,176) | 1,325 | (60.9)% |
| Net income (loss) before tax | (4,205) | 8,476 | (12,681) | (149.6)% |
| Texas margin tax expense | 101 | (65) | 166 | (255.4)% |
| Net income (loss) | (4,306) | 8,541 | (12,847) | (150.4)% |
| | | | | |
| Key performance metrics: | | | | |
| Gross margin | 30,026 | 36,962 | (6,936) | (18.8)% |
| Adjusted EBITDA | 9,239 | 19,730 | (10,491) | (53.2)% |

Revenues. Natural gas, NGLs and condensate revenue decreased by $20.9 million, or 38%, from $55.6 million for the year ended December 31, 2011 to $34.7 million for the year ended December 31, 2012. The decrease in natural gas, NGLs and condensate revenue is primarily due to declining NGL prices and a decrease in NGL volumes sold from our Panola County processing facilities. The average annual price of ethane decreased by 48% from $0.77 in 2011 to $0.40 in 2012, and the average annual price of propane decreased by 32% from $1.46 in 2011 to $1.00 in 2012. Similarly, the average annual price of isobutane, normal butane and natural gasoline decreased by 12%, 10%, and 8%, respectively, from 2011 to 2012. Declining NGL prices attributed to a $9.7 million decrease in our NGL sales from 2011 to 2012.

In addition, 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 revenue. As a result of this change in contractu